Decision 2003-085

EUB

EPCOR Distribution Inc.

2004 Distribution Tariff Application
Part A: 2004 Interim Distribution Rates

November 14, 2003

Alberta Energy and Utilities Board

Decision 2003-085

104-03450/

EPCOR Distribution Inc.

2004 Distribution Tariff Application
Part A: 2004 Interim Distribution Rates

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ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-085: EPCOR Energy Distribution Inc.
2004 Distribution Tariff Application
Part A: 2004 Interim Distribution Tariff
Application No. 1306821

Published by
Alberta Energy and Utilities Board
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ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

EPCOR DISTRIBUTION INC.
2004 DISTRIBUTION TARIFF APPLICATION
PART A: 2004 INTERIM RATES

Decision 2003-085
Application No. 1306821
File No. 1706-3

1 INTRODUCTION

With the passage of the new *Electric Utilities Act*, SA 2003, c.E-5.1 (EUA), which came into force on June 1, 2003, the municipal electric distribution systems of the Cities of Edmonton and Calgary became subject to the jurisdiction of the Alberta Energy and Utilities Board (Board). In particular, the Board became the regulatory authority for EPCOR Distribution Inc. (EDI) and ENMAX Power Corporation (EPC) for the purposes of approving distribution tariffs (DT) to be effective January 1, 2004.[1] The *Distribution Tariff Regulation*, AR 163/2003 (*DT Regulation*), required EDI and EPC to apply to the Board for approval of their DTs on or before October 1, 2003.[2] The *DT Regulation* requires the Board either to approve a final DT for EDI and EPC to take effect on January 1, 2004, or to approve an interim DT no later than November 30, 2003 to take effect on January 1, 2004.

In anticipation of receiving DT applications from EDI and EPC,[3] the Board issued a letter to interested parties on July 14, 2003, which included a Notice and proposed schedule intended to ensure that the Board could meet the deadlines prescribed in the *DT Regulation*. The Notice provided for a pre-hearing conference, which was held on September 12, 2003 (Pre-Hearing). Among other administrative matters dealt with at the Pre-Hearing, the Board heard submissions from parties with respect to issues that should be dealt with on an interim basis and those that could be left until the final proceeding. On September 17, 2003, the Board issued a further letter to parties setting out a revised schedule for the proceeding and a list of issues to be dealt with at the interim and final stages of EDI's and EPC's forthcoming DT applications. A copy of the Board's letter of September 17, 2003 is reproduced in Appendix 2 to this Decision.

As Required by the *DT Regulation*, the Board received an application from EDI dated October 1, 2003 requesting interim and final approval of EDI's 2004 DT (2004 DT Application or Application, with the interim portion being referred to as the 2004 Interim DT Application or Interim Application). The process for consideration of the Interim Application conformed to the schedule set out in the Board's September 17, 2003 letter as follows:

Information Requests (IRs) to EDI	October 10, 2003
IR Responses from EDI	October 20, 2003
Oral Hearing	October 27, 2003

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[1] EUA, section 102.

[2] *DT Regulation*, section 4(1).

[3] As well as applications under the *Regulated Default Supply Regulation*, AR 168/2003, from EPCOR Energy Services Inc. and EPC on behalf of ENMAX Energy Corporation.

The oral hearing was conducted in Edmonton from October 27-30, 2003, with oral argument and reply on October 30, 2003. Parties participating in the proceedings are shown in Appendix 1 to this Decision.

Although responses to undertakings given during the hearing were submitted after October 30, 2003, and are considered by the Board to form part of the formal record of the proceeding, for administrative purposes of this Decision, the Board considers the record to have closed on October 30, 2003.

2 EDI'S 2004 INTERIM APPLICATION

The Board notes that the EDI's 2004 DT comprises a Distribution Access Service (DAS) tariff and a System Access Service (SAS) tariff. For the purposes of this Decision, the Board will use the following terminology:

DAS revenue requirement	refers to the revenue requirement associated with the provision of DAS service.
DAS rates	refers to the rates used to generate the revenues required to meet the DAS revenue requirement.
SAS revenue requirement	refers to the costs associated with purchasing system access service from the AESO.
SAS rates	refers to the rates used to generate the revenues required to meet the SAS revenue requirement.
DT revenue requirement	refers to the sum of the DAS and SAS revenue requirements.
DT rates	refers to the combined DAS and SAS rates.

In its Interim Application, EDI requested the following approvals from the Board:

(a) pursuant to section 102 of the EUA, approval of EDI's DT for the 2004 Test Year in relation to the provision of service by means of EDI's electric distribution system;
(b) pursuant to section 4(4) of the *DT Regulation* and pending the Board's approval of EDI's 2004 DT on a final basis, approval on an interim refundable basis of EDI's DT to become effective January 1, 2004, the interim DT being comprised of:
    (i) EDI's existing 2003 rates for DAS as set out in DT Schedule 1 in the Interim Application;
    (ii) EDI's existing 2003 rates for SAS as set out in DT Schedule 2 in the Interim Application, subject to appropriate adjustment as the Board may determine to be just and reasonable following the Board's approval of final rates in respect of the Alberta Electric System Operator (AESO)'s 2003 General Tariff Application (GTA);[4] and
    (iii) EDI's Terms and Conditions of Service as set out in Schedule B to EDI's 2004 DT Application;

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[4] The Board has since approved the AESO's 2003 GTA in Decision 2003-077, dated November 4, 2003.

(c) pursuant to section 4(3) of the *DT Regulation*, approval on a final basis of EDI's Special Transmission Rider approved by Edmonton City Council on September 8, 2003 under Bylaw 13488 and more particularly described in section 6.2.1.1 of EDI's 2004 DT Application.

A summary of the 2004 DAS revenue requirement for EDI is shown in Table 1. EDI forecast the total 2004 SAS revenue to be $44 million.

Table 1. Summary of EDI 2004 DAS Revenue Requirement ($ millions)

Component	Distribution Access Service
Operating Costs	50.3
Depreciation and Amortization	14.9
Return on Rate Base	27.4
Hearing Costs	2.0
Revenue Offset	(1.4)
Revenue Requirement	93.2
Revenue from existing rates (2003)	93.6
Revenue Surplus/(Deficiency)	0.4

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In the following Sections of this Decision, the Board will address each of the DT revenue components.

3 OPERATING EXPENSE

3.1 Views of the Applicant

EDI requested an operating expense of $50.3 million for 2004, representing a $5.0 million increase over the 2003 estimate.

3.2 Views of the Interveners

CCA

CCA expressed concern over the significant increases in operating costs since 2000 and therefore submitted that the operating expenses should be tested before an increase is approved. Furthermore, CCA submitted that while considerable detail was provided on the operating expenses, there had been insufficient time during the interim process to test the material such that the Board should reduce the requested $50.3 million by $1.9 million.

PICA

PICA supported the views of CCA.

3.3 Views of the Board

The Board notes that EDI's forecast of operating expenses was not fully tested during the interim proceedings. Notwithstanding the lack of complete testing, the Board is not persuaded that it should make any reductions to EDI's requested interim tariffs in respect of forecast operating expenses. The Board considers EDI's forecast of operating expenses can be fully tested during the final proceedings.

The Board does not consider it necessary to give any guidance to EDI, in this interim Decision, respecting the appropriateness of any proposed operating expenditures for 2004. The Board expects EDI to exercise its management responsibilities and only undertake those expenditures EDI considers prudent and appropriate.

4 DEPRECIATION AND AMORTIZATION

4.1 Views of the Applicant

EDI forecast an amortization expense for 2004 of $14.9 million, which is an increase of $2.4 million over the 2003 estimate. EDI's practice has been to recover the cost of capital assets on a straight line basis over their estimated average service lives, which EDI considered to be consistent with Board practice. However, because EDI has not collected detailed statistical information regarding service lives and retirement dispersions of all of its assets, EDI has not used the Equal Life Group procedure generally approved by the Board for other utilities.

EDI proposed to use the calculations in the Capital Asset Review to establish the original cost of all property retirements in 2004, thereby making its capital asset recording practices generally consistent with the Board's practices. EDI submitted that, as statistically valid data sets are accumulated over the next few years, EDI would be able to provide traditional depreciation studies to the Board for its consideration.

4.2 Views of the Interveners

CCA

CCA submitted that although EDI filed a technical update, no review or assessment of this updated has yet been conducted. CCA considered this update to be partly responsible for the $2.4 million increase in 2004. Further, CCA noted that EDI had acknowledged a number of areas, such as depreciation practices, where EDI is at variance with some of the Board's traditional practices. For these reasons, CCA submitted that the Board should not grant the fully requested increases at this time and should approve a depreciation and amortization expense of $13.5 million instead of $14.9 million.

4.3 Views of the Board

The Board notes that EDI's forecast of amortization expense was not fully tested during the interim proceedings. Notwithstanding the lack of complete testing, the Board is not persuaded that it should make any reductions to EDI's requested interim rates in respect of forecast net amortization expense. The Board considers EDI's forecast of net amortization expense can be fully tested during the final proceedings.

5 HEARING COSTS

5.1 Views of the Applicant

EDI applied for a Hearing Cost Reserve Account to manage the hearing costs for both EDI and interveners associated with its 2004 DT. EDI proposed that the Board allow EDI to include $1.8 million in its forecast revenue requirement as a reasonable estimate of EDI's and interveners' total claimable hearing costs for 2004. Any variance from this forecast of the actual costs awarded by the Board would be included in the Reserve and then amortized over a future period approved by the Board in the context of EDI's next DT Application.

5.2 Views of the Interveners

The Hearing Cost Reserve Account was not opposed by interveners on an interim basis.

5.3 Views of the Board

The Board agrees with EDI that a Hearing Cost Reserve Account should be established effective January 1, 2004. The Board notes that this is consistent with the Boards treatment of hearing costs in respect of other utilities under the Board's jurisdiction.

The Board notes that EDI's forecast of hearing costs was not fully tested during the interim proceedings. Notwithstanding the lack of complete testing, the Board is not persuaded that it should make any reductions to EDI's requested interim rates in respect of forecast hearing costs. The Board considers EDI's forecast of hearing costs can be fully tested during the final proceedings

6 CAPITAL EXPENDITURES

6.1 Views of the Applicant

EDI forecast capital additions of $41.9 million for 2004, which is $9.9 million more than in 2003. EDI stated that even with this increase, the capital expenditures reflect a slower rate of system growth. A description of the capital projects that are forecast to be undertaken in 2004, as well as their cost and justification, was provided in EDI's Application.

6.2 Views of the Interveners

CCA

CCA expressed concern that in 2004 EDI is undertaking a significant amount of capital additions – 31% more than in 2003, and almost 50% more than in 2001. CCA submitted that it appeared that EDI has waited until 2004 to make up for a large portion of capital expenditures that perhaps could have been undertaken in prior years when it was under the Performance Based Regulation (PBR) regime. CCA noted that in 2003 capital additions were only about $200,000 higher than in 2002.

Since no full assessment has yet been undertaken of the business cases in support of the major capital expenditures, CCA was unable to make a reasoned assessment of whether the level of capital expenditures is reasonable, let alone determine the prudence of the expenditures.

6.3 Views of the Board

The Board notes that EDI's forecast of capital expenditures was not fully tested during the interim proceedings. Notwithstanding the lack of complete testing, the Board is not persuaded that it should make any reductions to EDI's requested interim rates in respect of forecast capital expenditures. The Board considers EDI's forecast of capital expenditures can be fully tested during the final proceedings.

The Board does not consider it necessary to give any guidance, in this interim Decision, to EDI respecting the appropriateness of any proposed capital expenditures for 2004. The Board expects EDI to exercise its management responsibilities and only undertake those expenditures EDI considers prudent and appropriate.

7 RETURN

7.1 Views of the Applicant

In the Generic Cost of Capital proceeding, EDI applied for a capital structure of 45% equity and 55% debt with a rate of return on equity (ROE) of 11%. EDI considered these values to be reasonable and, therefore, appropriate to be used as placeholders for the Interim Application.

In its 2004 DT Application, EDI noted that it was previously regulated under a Performance Based Regulation (PBR) regime rather than a traditional cost of service methodology. Under the PBR regime, EDI's rates were not established based on a specific return on debt and equity. EDI submitted, therefore, that debt and equity returns for years prior to 2004 did not provide a meaningful comparison to the values proposed by EDI for 2004 in its Application.[5]

7.2 Views of the Interveners

CCA

CCA submitted that the requested ratios and rates were unreasonable and that the capital structure and return approved in Decision 2003-071 for ATCO Electric Ltd (AE) should be used as placeholders pending the Board's determinations in the Generic Cost of Capital proceeding. Applying the values approved for AE of 35% equity and 9.4% ROE as placeholders, the 2004 revenue requirement for EDI would be reduced by approximately $2.7 million.

7.3 Views of the Board

For the purposes of this interim Decision, the Board must decide what placeholders should be used. The following options were suggested by the parties:

1. 45% equity & 55% debt with an 11% ROE as proposed by EDI
2. 35% equity & 65% debt with a 9.4% ROE as per Decision 2003-071 for AE.

Although the division of the Board assigned to the Generic Cost of Capital proceeding (Generic Cost of Capital Division) has made it clear that it has not yet determined whether it will finally determine capital structure and cost of capital matters for any utility regulated by the Board, including EPC, the Cost of Capital Division may ultimately exercise its discretion to do so following the completion of that proceeding. The division of the Board assigned to EDI's 2004 DT Application (Municipal Tariff Division) does not intend to anticipate the decisions to be made by the Generic Cost of Capital Division, particularly since the hearing before that Division commenced on November 12, 2003.

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[5] 2004 DT Application, page 48, lines 30-34.

In any event, the Board agrees with interveners that the capital structure and ROE placeholders proposed by EDI in the Interim Application cannot be justified on an interim basis. The placeholders proposed by EDI are higher than those that the Board has approved in the recent past. For the purposes of this interim Decision, the Board considers that it ought to have regard to values approved by the Board in relation to investor-owned electric distribution systems, such as AE in Decision 2003-071 and Aquila Networks Canada (Alberta) Ltd. (ANCA) in Decision 2003-019. The Board also considers it reasonable to take into account the placeholders approved by the Board for EPC in Decision 2003-084.

Based on these considerations, the Board has determined that a capital structure of 60% debt and 40% equity with a return on equity of 9.4% are appropriate placeholders for the purposes establishing the level of interim rates. EDI's proposed capital structure and ROE would result in a revenue requirement component of $27.4 million. The placeholders approved by the Board would result in a revenue requirement return component of $25.0 million, a reduction of $2.4 million.

8 REVENUE DEFICIENCY/SURPLUS

8.1 Views of the Applicant

EDI applied for a total DAS revenue requirement of $93.2 million, which is a $2.7 million increase over the total re-forecast revenue requirement for 2003.

EDI noted that revenues at existing rates would generate $89.6 million. EDI proposed that an interim Rider D1, which would generate $4.0 million, should be approved on an interim basis. EDI submitted that Rider D1 represented the sum of the 2003 DAS revenue riders put in place pursuant to the Flow-Through Rider adjustment mechanism approved by Edmonton City Council in Bylaw 13488.[6] Absent the Flow-Through Rider adjustment mechanism, EDI submitted that these riders would have formed part of the 2003 base rates and, therefore, should be considered as a component of existing rate levels. With Rider D1, EDI's forecast revenues at existing rates would total $93.6 million.

EDI characterized Exhibit 004-01 submitted by CCA as a "mathematical exercise" and submitted that CCA had not adduced any evidence to support the decreases shown in Exhibit 004-01. EDI further argued that interveners made no attempt to test the revenue requirement components to any degree.

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[6] BR-EDI-2(a).

8.2 Views of the Interveners

CCA

CCA submitted that the overall revenue requirement for EDI should be reduced from $93.2 million to $84.7 million, for a net reduction of $8.5 million as proposed in Exhibit 004-01. CCA considered that when there are significant proposed increases on an interim basis, which have not been fully explored and tested, there should be some adjustment to ensure that the interim rates do not result in customers overpaying the utility. However, CCA recognized that EDI must also be provided a reasonable level of the proposed cost increase.

PICA

PICA largely supported CCA's views on revenue requirement as proposed in Exhibit 004-01. PICA submitted that the existing rates should be reduced by approximately 9% or that the $4 million related to the Rider D1 of $0.0006/kWh should not be approved for January 1, 2004.

8.3 Views of the Board

The Board notes that a number of revenue requirement components are presently untested and warrant further exploration during final proceedings. There is the possibility of reductions to other components of the revenue requirement and a possible change to the return component after the final proceedings.

The Board notes that EDI's forecast 2004 revenue at existing 2003 rates is $89.6 million and that EDI has also proposed an interim Rider D1 that would generate a further $4.0 million, for a total forecast 2004 revenue of $93.6 million.

EDI's forecast 2004 revenue requirement is $93.2 million, some $0.4 million lower than EDI's forecast revenue including Rider D1. Reducing EDI's forecast revenue requirement to reflect the Board's placeholders for return and capital structure would reduce EDI's forecast 2004 revenue requirement by $2.4 million to $90.8 million, some $2.8 million below EDI's forecast revenue including Rider D1.

The Board further notes from Appendix 3 to this Decision that EDI is proposing an overall $2.9 million increase from the 2003 revenue requirement whereas the interveners are suggesting that a $8.5 million reduction may result after the final proceedings.[7] Given the wide range of possible outcomes following the final proceeding, and while the Board accepts EDI's position that Rider D1 should be considered as part of the 2003 base rates, the Board is not persuaded that the full amount of the proposed Rider D1 should be approved on an interim basis.

The Board considers that it would be appropriate to adjust the level of Rider D1 so that 2004 forecast revenues are equal to the adjusted revenue requirement of $90.8 million as set out above. This adjustment requires that Rider D1 generate $1.2 million rather than the $4.0 million proposed by EDI and, therefore, requires that Rider D1 be set at $0.00018/kWh rather than the $0.0006/kWh proposed by EDI.

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[7] The Board notes that the 2003 revenue requirement has been calculated using a forecast 2003 return of $32.6 million. This is $5.2 million greater than the return requested by EDI in 2004, which indicates that the 2003 return may not be an appropriate standard upon which to measure requested increases or decreases in revenue requirement for 2004.

Accordingly, the Board approves the continuation of EDI's current rates on an interim refundable basis with a reduction to the proposed Rider D1 to $0.00018/kWh, effective January 1, 2004 as shown on the Schedule A DAS Price Schedules attached.

The Board notes that there was no opposition voiced respecting the proposed interim EDI SAS Price Schedules. The Board is satisfied that it would be appropriate to approve the requested interim EDI SAS Price Schedules since these proposed SAS Price Schedules will flow through actual AESO charges in 2004. Accordingly, the Board approves the proposed SAS on an interim refundable basis effective January 1, 2004 as shown on Schedule B SAS Price Schedules attached.

9 RATE DESIGN

9.1 Views of the Applicant

EDI did not propose changes to its rate design on an interim basis.

9.2 Views of the Interveners

Interveners agreed that there should be no change to EDI's rate design on an interim basis.

9.3 Views of the Board

The Board agrees that there should not be any changes to EDI's rate design on an interim basis.

10 TRANSMISSION ACCESS CHARGES (TAC) DEFERRAL ACCOUNT

10.1 Views of the Applicant

EDI proposed a deferral account for the difference between the AESO's actual 2004 charges and SAS revenue recovered by EDI from customers through its 2004 DT. EDI based its proposal on the premise that the standard, province-wide transmission tariff should flow through to retailers as transparently as possible, thereby accurately communicating the price signals which the Board has determined to be appropriate. EDI also noted that it has no control over the AESO's charges relating to SAS, and is therefore not in a position to forecast the cost to EDI on a reasonably accurate basis.

EDI noted that it does have limited ability to control substation peak demand through seasonal feeder switching, and takes steps where reasonably practicable to minimize these demand costs and optimize system efficiency. EDI considered that these activities are a normal part of good utility practice, and did not consider that additional financial incentives are required to encourage this activity.

EDI proposed to record, on a calendar year basis, the total cost of transmission related charges from the AESO and the total revenue associated with EDI's SAS rates. The difference between the cost and revenue associated with SAS will be to the account of customers, and the deferral account will be amortized over the 12-month period following the year in which the deferral account accrued.

EDI did not consider the request by PICA to separate transmission costs to be as simple as it might seem. EDI submitted that the transmission costs can not be easily separated into demand-related or energy-related cost components.

10.2 Views of the Interveners

CCA

CCA supported the submissions of PICA with respect to the TAC deferral account.

PICA

PICA submitted that the TAC deferral account was acceptable on an interim basis subject to the two following stipulations:

1. The deferral account should be by component and by rate class and;
2. EDI should be incented to minimize these charges by assuming volume risk and that this concept should be open to further testing in the context of the main hearing.

10.3 Views of the Board

The Board notes that EDI's past practice has been to true-up transmission access charges on a yearly basis using a TAC deferral account.[8] The Board agrees with EDI that a TAC deferral account should be continued effective January 1, 2004. The Board notes that the structure and mechanics of EDI's proposed TAC deferral account was not fully tested during the interim proceeding. However, the Board is not persuaded that it should make any changes to the proposed TAC deferral account on an interim basis.

Accordingly, the Board approves EDI's TAC deferral account as proposed in the Application on an interim basis.

11 SPECIAL TRANSMISSION RIDER (2003)

11.1 Views of the Applicant

EDI's Special Transmission Rider relates to two specific items in its TAC deferral account which relate to 2003. The Special Transmission Rider was authorized by the Edmonton City Council on September 8, 2003 under Bylaw 13488.[9] EDI is requesting Board approval to continue this Rider pursuant to Section 4(3) of the *DT Regulation*.

The purpose of the Special Transmission Rider is to refund or recover, as the case may be, the following two AESO TAC-related items:

- The actual charges or refunds to EDI under the AESO's Rate Riders "B" and "C" applicable to the period from October 1, 2003 to December 31, 2003; and

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[8] EDI Application Binder I of 5 pg 28 and BR-EDI-I

[9] BR-EDI-2(a).

- The actual Engage Article 24 refund to EDI from the AESO in excess of the $4.0 million EDI has already refunded to customers during 2003 in respect of that refund.[10]

The level of the Special Transmission Rider is currently set at $(0.00027)/kWh (i.e. a refund rider) and will terminate on December 31, 2004 in accordance with Bylaw 13488. As required under Section 12 of the Bylaw, EDI will adjust the amount of the Special Transmission Rider to reflect EDI's actual costs within one month following notification of final amounts from the Board or the AESO, as applicable.

11.2 Views of the Interveners

No interveners opposed the Special Transmission Rider (2003).

11.3 Views of the Board

Section 4(2) of the *DT Regulation* provides for EDI to apply for continuation of its Special Transmission Rider (2003) in the following terms:

> **(2)** The application under subsection (1) may include any distribution tariff riders approved by the council of the municipality on or before October 1, 2003 for recovery of deferral accounts in place for costs or charges incurred before January 1, 2004.

Section 4(3)(a) of the *DT Regulation* restricts the Board's discretion in relation to these pre-approved DT riders:

> **(3)** On receiving an application under subsection (1), the Board must, not later than November 30, 2003,
>
> (a) approve without change or alteration any distribution tariff riders referred to in subsection (2) … .

The Board notes that EDI's Special Transmission Rider (2003) was approved by Edmonton City Council prior to October 1, 2003.[11] Therefore, it is subject to subsections 4(2) and 4(3)(a) of the *DT Regulation*.

The Board agrees with EDI that the Special Transmission Rider (2003) should continue effective January 1, 2004 and should reflect any AESO refund in excess of the $4.0 million, since this change is consistent with Section 12 of the Edmonton City Council's approval of the Rider reflected in Bylaw 13488.

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[10] The Engage Article 24 refund was approved by the Board in Decision 2003-054 on July 8, 2003.

[11] BR-EDI-2(a).

12 REGULATED RATE TARIFF (RRT) ARRANGMENT

12.1 Views of the Applicant

EDI applied to the Board pursuant to section 104 of the EUA and section 11 of the *Regulated Default Supply Regulation*, AR 168/2003, (*RDS Regulation*) for approval of an arrangement (Arrangement) between EDI and EPCOR Energy Services Inc. (EESI) under which EESI will perform the obligations of EDI under the EUA and the *RDS Regulation* to:

- provide electricity services to eligible customers within the EDI service area; and
- perform the obligations of EDI to prepare and apply to the Board for approval of an RRT (Arrangement Application).[12]

EDI noted that an arrangement similar to the Arrangement had been entered into prior to regulatory authority over EDI being conferred on the Board (Prior Arrangement). The Prior Arrangement had been approved by EDI's previous regulator, Edmonton City Council, but EDI considered that the transfer of jurisdiction to the Board made it appropriate for the Board to approve the Arrangement effective January 1, 2004, notwithstanding the terms of section 155 of the EUA.

EDI submitted that approval of the Arrangement Application was in the public interest. Specifically, approval of the Arrangement Application would allow for the continuation of an arrangement between EDI and EESI with a demonstrated track record of having facilitated reliable and efficient RRT service in the EDI service area.

12.2 Views of the Interveners

No party opposed approval of the Arrangement, although the CCA submitted that it should be approved only on an interim basis since the RRT Arrangement Issue was included in the column entitled "EESI Interim RRT Issues" in Exhibit 1-5 (see Appendix 2 to this Decision).

12.3 Views of the Board

The Board has for disposition an application by EDI requesting final approval of an Arrangement appointing EESI as the RRT provider in the EDI service territory. Section 104 of the EUA authorizes EDI, as the owner of an electric distribution system, to authorize another person to carry out some or all of EDI's functions as owner under the EUA and its regulations, including the *RDS Regulation*. Section 11 of the *RDS Regulation* requires an owner subject to the Board's jurisdiction to obtain Board approval of any such arrangement.

At the Pre-Hearing on September 12, 2003, EDI advised the Board that EDI would seek Board approval of the Arrangement. At the same time, EPC made a similar indication in relation to its arrangement with EEC. However, in EPC's 2004 DT Application, EPC indicated its view that Board approval of the existing arrangement between EPC and EEC did not require Board approval because it had previously been approved by Calgary City Council and because section 155 of the EUA preserved that approval.

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[12] Application No. 1316786.

Some question was raised during the interim proceeding as to whether the Board was obliged to treat EDI and EPC consistently. However, the Board is of the view that, should it agree with EPC that no further Board approval of its existing arrangement is required, nothing prevents the Board from approving EDI's Arrangement. In the Board's view, if EDI considers it prudent to seek Board approval of the Arrangement, notwithstanding that the previous approval by Edmonton City Council of the Prior Arrangement may be unaffected by virtue of section 155 of the EUA, the Board may exercise its discretion to approve the Arrangement.

As to whether any Board approval of the Arrangement should be interim or final, the Board notes that the Arrangement Application was clear on its face that EDI was seeking final approval of the Arrangement, albeit at the interim stage of these proceedings. The Board also considers that the issues list in Exhibit 1-5 (Appendix 2) only identified those issues to be considered during the interim proceeding and was not intended to convey whether or not the issue would be decided on an interim or final basis following the interim proceeding.

Except for whether the Board's approval should be interim or final, the Board notes that the Arrangement Application is unopposed. The Board has been presented with no evidence, and is otherwise not aware, of any difficulties respecting the existing appointment of EESI as the regulated rate provider in the EDI service territory.

The Board is satisfied that EESI is capable of providing reliable and efficient RRT service in the EDI service area. Furthermore, the Board will have ongoing regulatory authority with respect to EESI's RRTs and the quality of service provided by EESI. The Board also notes that section 104(2) of the EUA ensures that the Arrangement in no way derogates from EDI's responsibilities and duties to carry out the functions being assigned to EESI pursuant to the Arrangement.

Accordingly, the Board approves the RRT Arrangement on a final basis.

13 TERMS AND CONDITIONS & FEES FOR SERVICES

13.1 Views of the Applicant

EDI submitted that the Terms and Conditions and Fees for Services should be approved as filed on an interim basis effective January 1, 2004.

13.2 Views of the Interveners

Interveners agreed that the Terms and Conditions and Fees for Services could be approved on an interim basis.

13.3 Views of the Board

The Board agrees with EDI and the interveners that the Terms and Conditions and Fees for Services and Connections should be accepted as filed on an interim basis.

Accordingly the Board accepts the EDI Terms and Conditions and Fees for Services Schedule C Service Terms and Conditions and Connections Schedule D Service Connections Terms and Conditions.

14 SUMMARY OF APPROVALS

This section is provided for the convenience of readers. In the event of any difference between the approvals in this section and those in the main body of the report, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board approves the continuation of EDI's current rates on an interim refundable basis with a reduction to the proposed Rider D1 to $0.00018/kWh, effective January 1, 2004 as shown on the Schedule A DAS Price Schedules attached. 9
2. The Board notes that there was no opposition voiced respecting the proposed interim EDI SAS Price Schedules. The Board is satisfied that it would be appropriate to approve the requested interim EDI SAS Price Schedules since these proposed SAS Price Schedules will flow through actual AESO charges in 2004. Accordingly, the Board approves the proposed SAS on an interim refundable basis effective January 1, 2004 as shown on Schedule B SAS Price Schedules attached. 9
3. Accordingly, the Board approves EDI's TAC deferral account as proposed in the Application on an interim basis. 10
4. The Board agrees with EDI that the Special Transmission Rider (2003) should continue effective January 1, 2004 and should reflect any AESO refund in excess of the $4.0 million, since this change is consistent with Section 12 of the Edmonton City Council's approval of the Rider reflected in Bylaw 13488. 11
5. Accordingly, the Board approves the RRT Arrangement on a final basis. 13
6. Accordingly the Board accepts the EDI Terms and Conditions and Fees for Services Schedule C Service Terms and Conditions and Connections Schedule D Service Connections Terms and Conditions. 13

Dated in Calgary, Alberta on November 14, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

N. W. MacDonald

N.W. MacDonald, P.Eng
Presiding Member

RLock.

R. G. Lock, P. Eng.
Member

John Douglas

J. I. Douglas, FCA
Member

APPENDIX 1–HEARING PARTICIPANTS

Principals and Representatives (Abbreviations Used in Report)	Witnesses
ENMAX Power Corporation (EPC) and ENMAX Energy Corporation (EEC) L. A. Cusano, Esq. D. A. Wood	EEC Dr. Ed Overcast, PhD Stuart Berry J. R. Joyce Bob Cummings Brad Thompson Allan Buchignani EPC K. Phillips Brad Thompson Allan Buchignani
EPCOR Energy Services (EESI) and EPCOR Distribution Inc. (EDI) J. M. Liteplo, Esq. D. E. Crowther, Esq.	EESI B. DeNeve Brian Gerdes EDI B. DeNeve Rick Cowburn
ATCO Electric Limited L. G. Keough, Esq. Kristen Lozynski, Esq.	
Calgary Industrial Group and Calgary Building Owners Coalition L. L. Manning, Esq	
Consumers Coalition of Alberta J. A. Wachowich	
Direct Energy Preferred P. Nigol	
Industrial Power Consumer Association M. S. Forster, Esq. Dan B. Macnamara	
Edmonton Extended Care Group (EECG), St Michael's Long Term Care Center Society, Devonshire Care Centre Roger Bellows A. O. Ackroyd, Q. C	

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Calgary Care Center Group (CCCG) Glamorgan Care Center, Mayfair Care Centre, Newport Harbour Care Centre Roger Bellows A. O. Ackroyd, Q. C	
Public Institutional Consumers of Alberta Nancy J. McKenzie, Esq Raj Retnanandan	
The City of Calgary D. I. Evanchuk, Esq.	
The Cities of Lethbridge, Red Deer, and University of Alberta Phyllis A. Smith, Q. C.	
Utilities Consumer Advocate C. R. McCreary Roger W. Jackson	
Board Panel N. W. MacDonald, P. Eng. R. G. Lock, P. Eng. J. I. Douglas, FCA	
Board Counsel Allan Domes, Esq.	
Board Staff Brian Ploof Kim Koshelanyk Wayne Taylor	

APPENDIX 2-BOARD PRE-HEARING CONFERENCE DECISIONS

File No. 1210-1, 1706-3, 1210-2, 1706-4

September 17, 2003

2004 DISTRIBUTION TARIFF (DT) APPLICATIONS
ENMAX POWER CORPORATION (EPC), Application No. 1306819
EPCOR DISTRIBUTION INC. (EDI), Application No. 1306821

2004 REGULATED RATE TARIFF (RRT) APPLICATIONS
ENMAX ENERGY CORPORATION (EEC), Application No. 1306818
EPCOR ENERGY SERVICES (EESI), Application No. 1306820

RE: MATTERS DISCUSSED AT PRE-HEARING CONFERENCE

The purpose of this letter is to set out the Board's decisions respecting matters discussed at the Pre-Hearing Conference held at the Board's Hearing Room in Edmonton on September 12, 2003.

Oral vs. Written Interim Proceeding

The Board has decided to defer a decision on whether the interim proceeding should be an oral or written proceeding until parties have had the opportunity to review the DT and RRT Applications that are required to be filed on or before October 1, 2003.

Interested parties are requested to submit written comments to the Board on or before October 10, 2003 respecting whether the interim proceeding should be an oral or written process. Parties should also indicate any additional issues identified in their detailed review of the interim application that they consider must be dealt with in the interim proceeding. The Board will then be in a position to make a final decision on the interim issues and process on or before October 17, 2003. In the meantime the Board will maintain the interim oral hearing dates of October 27-31, 2003 and the currently scheduled venue located at the 12th floor, 10055-106 Street, Edmonton, Alberta.

Interim and Final Issues Lists

The Board has included an updated copy of the Interim and Final Issues Lists incorporating the comments received by the Board during the Pre-Hearing Conference.

Location and Order of Final Hearing

The Board concurs with the Pre-Hearing Conference consensus that the forthcoming Applications should be heard on a company basis with each company's DT Application heard first followed by that company's RRT Application.

The Board has decided to commence the Final Proceeding in Edmonton on March 1, 2003 and hear the EPCOR DT and RRT Applications. Immediately after hearing the EPCOR Applications, the Board will move the proceedings to Calgary and hear the ENMAX DT and RRT Applications.

The Board has reflected the above Board decisions on the attached revised Hearing Schedule.

Exhibit Numbering
As set out in the July 14, 2003 Notice, exhibit numbers will be assigned as follows:

Applicant/Intervener	Pre-Assigned Exhibit Numbers
Board	001-XX
ENMAX	002-XX
EPCOR	003-XX
Intervener 1	004-XX
Intervener 2, etc	005-XX

Interveners wishing to submit evidence should contact Board staff to obtain their pre-assigned block of Exhibit numbers.

The Board has marked the Notice of these proceedings as Exhibit 1-1. At the recommencement of proceedings, the Board will mark the Pre-Hearing Conference package of material as Exhibit 1-2 and this letter as Exhibit 1-3.

Please direct any questions respecting these matters to Brian Ploof at (780) 422-2597.

Yours truly,

<original signed by>

Brian Ploof

Application Officer

Attachments:
Revised Hearing Schedule
Revised Interim/Final Issues Lists

Revised Schedule for 2004 ENMAX/EPCOR DT and RRT Municipal Electric Service Proceedings dated September 15, 2003

Event	Date
Notice	July 14, 2003
Register as an Intervener	August 15, 2003
Initial Applicant Issues List	September 2, 2003
Initial Intervener Issues List	September 8, 2003
Pre-Hearing Conference (9:00 AM)	September 12, 2003
Initial Board Issues List (Interim and Final Tariffs)	September 15, 2003
Applications Filed (Latest date permitted by law)	October 1, 2003 (or earlier)
Comments by Interested Parties respecting Interim Proceeding (Oral vs. Written)	October 10, 2003
Board Decision respecting whether Interim proceeding is Oral or Written	October 17, 2003
Interim Tariff Proceeding Schedule (If Oral)	
IRs to Applicants	October 10, 2003
Applicants Responses to IRs	October 20, 2003
Hearing on ENMAX and EPCOR Interim Tariffs (oral argument and reply) 12th Floor, 10055-106 Street, Edmonton, Alberta	October 27-31, 2003
Interim Tariff Proceeding Schedule (If Written)	
IRs to Applicants	October 10, 2003
Applicants Responses to IRs	October 20, 2003
Written Argument	October 27, 2003
Written Reply	October 31, 2003
Interim Board Decision(s)	
Initial Board Decision	November 14, 2003
Re-filings by Applicants	November 21, 2003
Final Decision(s)	November 28, 2003
Final Proceeding	
IRs to Applicants	November 10, 2003
Applicant Responses to IRs	December 10, 2003
Intervener Evidence	January 14, 2004
IRs to Interveners	January 28, 2004
Intervener Responses to IRs	February 12, 2004
Rebuttal Evidence	February 23, 2004
Hearing of EPCOR DT and RRT Applications in Edmonton 12th Floor, 10055-106 Street, Edmonton, Alberta	March 1-XX, 2004 1:30 pm
Hearing of ENMAX DT and RRT Applications in Calgary Govier Hall 640-5th Avenue SW Calgary, Alberta	March XX-26, 2004
EPCOR DT and RRT Argument	April 26, 2004
EPCOR DT and RRT Reply	May 17, 2004
ENMAX DT and RRT Argument	May 3, 2004
ENMAX DT and RRT Reply	May 24, 2004
Initial Decision(s)	August 10, 2004
Re-filings by Applicants	August 24, 2004
IRs on Re-filings (if Board determines necessary)	August 31, 2004
Responses to IRs	September 6, 2004
Submissions on Re-filings	September 13, 2004
Reply Submissions	September 20, 2004
Final Decision(s)	September 30, 2004

TABLE 1-REGULATED RATE TARIFF INTERIM AND FINAL ISSUES LISTS UPDATED SEPTEMBER 15, 2003

REGULATED RATE TARIFF	EESI Interim RRT Issues	EEC Interim RRT Issues	EESI/EEC Final RRT Issues
RRT Energy Rate	1. Final Approval of Negotiated Settlement for residential energy transition rate. (Otherwise same issues as per EEC) 2. Reasonableness of interim non-residential RRT flow-through energy rate	1. Final approval of the energy transition rate 2. RFP process 3. Fairness and appropriateness of the RFP process 4. Terms and conditions of the RFP 5. Bidder's list and bidder qualification criteria 6. RFP response evaluation criteria 7. Results and transparency of the RFP process 8. Contract terms with and contractual obligations of the successful bidder(s) 9. Derivation of load forecast underlying the RFP volumes 10. Derivation of number of energy blocks to be procured 11. Derivation of energy block size(s) and type (e.g., baseload, peak) 12. Determination of product terms (length) 13. Risk minimization objectives and strategy on behalf of RRT customers 14. RRT energy charge rate structure 15. RRT Energy Deferral account structure, application to billing and audit review 16. Reasonableness of interim non-residential RRT flow-through energy rate	1. Non-residential RRT flow-through energy rate 2. RRT lifeline rate 3. Rate classification definitions
RRT Non-Energy Rate	1. Final Approval of Negotiated Settlement if it includes non-energy rate. 2. Other wise EESI not requesting any increase to non-energy 2003 retail charge on an interim basis effective January 1, 2004	1. Reasonableness of interim refundable RRT non-energy charges	1. Non-energy charges 2. Return margin - percentage and on what RRT components 3. Allocation of Corporate costs 4. Non-energy cost allocation (fixed versus variable) 5. Non-energy cost allocation (regulated versus non-regulated) 6. RRT lifeline rate
RRT Billing Presentation	1. Distribution & transmission charges shown separately	1. Distribution & transmission charges shown separately	

REGULATED RATE TARIFF	EESI Interim RRT Issues	EEC Interim RRT Issues	EESI/EEC Final RRT Issues
RRT Terms and Conditions	1. Reasonableness of interim RRT terms and conditions 2. Reasonableness of interim RRT fees for additional services	1. Reasonableness of interim RRT terms and conditions 2. Reasonableness of interim RRT fees for additional services	1. RRT Terms and conditions 2. RRT Fees for additional services
Authorization of RRT Provider	1. EDI authorization of EESI as RRT Provider	1. EPC authorization of EEC as RRT Provider	

TABLE 2-DISTRIBUTION TARIFF (DT) INTERIM AND FINAL ISSUES LISTS UPDATED SEPTEMBER 15, 2003

DT APPLICATION	EDI Interim DT Issues	EPC Interim DT Issues	EDI/EPC Final Issues
Changes in Level of DT Rates	EDI not requesting any increase to EDI 2003 rate levels on interim basis effective January 1, 2004	EPC is requesting an increase to EPC 2003 rate levels on an interim basis effective January 1, 2004. Reasons for increase to be examined	Final Requested changes to 2003 rate levels not known at this time
Section 3 – Load and Revenue Forecasts	None subject to confirmation of no DT interim increase	Changes in load and revenues from 2003.	Economic parameters Customer growth rates - year end and average KWh by customer class Revenue by customer class
Section 4 – Operating Expenses	None subject to confirmation of no DT interim increase	Material changes in O & M from 2003. Allocation of costs between DT and RRT	Corporate Cost Allocation of O&M expenses within distribution companies (i.e. distribution, transmission, commercial services, and outside municipal boundaries expenses) Historical O&M expenses
Section 5 – Other Revenue Requirement Items	Final Approval of implementation of Deferral account for transmission access charges	Final Approval of implementation of Deferral account for transmission access charges 2. Final Approval of Current deferral account dedicated to the 2000 Deficiency Rider	Transmission access charge forecast and deferral Account Hearing Cost Reserve Account Dividend payout policies Self Insurance Reserve Account (EDI)
Section 6 – Rate Base	None subject to confirmation of no DT interim increase	Review Rate Base Valuation Major 2004 Capital Additions	Capital asset values per Notice Attachment 4 and PICA Sep 8, 2003 issues letter 2004 capital expenditures Financing of rate base. Accumulated depreciation. Contributions in aid of construction and necessary working capital (EPC). Asset transfer values Working capital requirements (EPC). Historical capital additions. Historical contributions
Section 7 – Depreciation and Amortization	None subject to confirmation of no DT interim increase	Changes from 2003	Depreciation/Amortization Methods Depreciation/Amortization Rates by Asset Class

APPENDIX 3-EDI 2004 DAS REVENUE REQUIREMENT

EDI DAS Revenue Requirement

(Consists of 1 page)

2004 EDI DAS Revenue Requirement

Component	Per EDI 2003	Per EDI 2004	Per Board Interim 2004	Per Interveners 2004
Operating expense	45,300	50,300	50,300	48,500
Depreiation and Amortization	12,500	14,900	14,900	13,500
Hearing Cost	1,800	2,000	2,000	0
Return	32,600	27,400	25,000	24,500
Revenue Offset	(1,900)	(1,400)	(1,400)	(1,800)
Total Rev Requirement	90,300	93,200	90,800	84,700
Rev Req Increase(Decrease)		2,900	-2,400	-8,500
Revenues (absent Rider D1)	89,600	89,600	89,600	84,700
Interim Rider D1 Revenues	4,000	4,000	1,200	0
Revenues (including Rider D1)	93,600	93,600	90,800	84,700
Revenue Surplus(Deficiency)	3,300	400	0	0

Note 1: Return per Board calculated from Exhibit 004-001 using a 60% Debt and 40% Equity Capital Structure
Note 2: Rider D1 per Board calculated at $.00018 (1200/4000 x $.00060/kWh)
Note 3: The Board notes that if the 2003 return were lowered to the level of the requested 2004 return the increase being requested by EDI would increase by $5.2 million to a total of $8.1 million.($5.2 million plus $2.9 million)

2004 EDI DAS Revenue Requirement

Component	Per EDI 2003	Per EDI 2004	Per Board Interim 2004	Per Interveners 2004
Operating expense	45,300	50,300	50,300	48,500
Depreiation and Amortization	12,500	14,900	14,900	13,500
Hearing Cost	1,800	2,000	2,000	0
Return	32,600	27,400	25,000	24,500
Revenue Offset	(1,900)	(1,400)	(1,400)	(1,800)
Total Rev Requirement	90,300	93,200	90,800	84,700
Rev Req Increase(Decrease)		[redacted]	[redacted]	[redacted]
Revenues (absent Rider D1)	89,600	89,600	89,600	84,700
Interim Rider D1 Revenues	4,000	4,000	1,200	0
Revenues (including Rider D1)	93,600	93,600	90,800	84,700
Revenue Surplus(Deficiency)	3,300	400	0	0

Note 1: Return per Board calculated from Exhibit 004-001 using a 60% Debt and 40% Equity Capital Structure
Note 2: Rider D1 per Board calculated at $.00018 (1200/4000 x $.00060/kWh)
Note 3: The Board notes that if the 2003 return were lowered to the level of the requested 2004 return the increase being requested by EDI would increase by $5.2 million to a total of $8.1 million.($5.2 million plus $2.9 million)

SCHEDULE A-EDI DAS PRICE SCHEDULES

EDI DAS Tariff
Schedule 1.doc

(Consists of 37 pages)

DT - Schedule 1

Distribution Access Service Tariff
(Interim 2004)

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Distribution Access Charges – Rate Schedule

Residential Service

Applicable: To all residential services that are served by EPCOR DISTRIBUTION and which have an energy meter. Residential Service is only available to single or two family dwellings consisting of a suite of rooms provided with sleeping and cooking facilities, which is being used primarily for domestic use. Where a business is conducted from a dwelling that it is also used for domestic purposes, the Residential Service is no longer applicable if the service is larger than 200 amps.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	R1
Off-Peak Variable Charge (per kWh)	R2
Site Charge (per Day)	R3
Minimum Variable Charge (per Minimum kW per Day)	R8
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Commercial/Industrial Service < 50 kVA

Applicable: This rate is applicable to services that have a normal maximum demand of less than 50 kVA. These services will have energy meters or will have energy consumption on an estimated basis. This rate is also applicable to all services for which no other rate is applicable.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	SC1
Off-Peak Variable Charge (per kWh)	SC2
Site Charge (per Day)	SC3
Minimum Variable Charge (per Minimum kW per Day)	SC8
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Commercial/Industrial Service 50 kVA to <150 kVA

Applicable: This rate is applicable to services that have a normal maximum demand of greater than or equal to 50 kVA and less than 150 kVA. These services will have demand meters.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	MC1
Off-Peak Variable Charge (per kWh)	MC2
Site Charge (per Day)	MC3
Demand Charge (per kVA per Day)	MC4
Minimum Variable Charge (per Minimum kVA per Day)	MC8
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Commercial/Industrial Service 150 to < 5,000 kVA

Applicable: This rate is applicable to sites that have a normal maximum demand of greater than or equal to 150 kVA and less than 5,000 kVA. These services require an interval-recording meter. This rate is applicable to all services that are served at the secondary voltage of the transformer, normally with a delivery voltage of below 1,000 volts.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	TOU1
Off-Peak Variable Charge (per kWh)	TOU2
Site Charge (per Day)	TOU3
Demand Charge (per kW per Day)	TOU4
Minimum Variable Charge (per Minimum kW per Day)	TOU5
Power Factor Charge (per kVAr per Day)	TOU6
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

A Minimum Variable Charge applies to all sites. Minimum Variable Charge may be waived when a site was constructed for redundancy and the load exhibits absolute diversity.

Where the Power Factor is less than 90% during the interval of the peak daily demand, the Power Factor Charge shall apply.

The kVAr is the maximum kVAr, in excess of the kVAr at 90% power factor calculated for each interval during the billing period.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Primary Commercial/Industrial Service 150 to < 5,000 kVA

Applicable: This rate is applicable to sites that have a normal maximum demand of greater than or equal to 150 kVA and less than 5,000 kVA. These services require an interval-recording meter. This rate is applicable to all services that are served at the primary distribution voltage, normally with a delivery voltage of above 1,000 volts.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	TOUP1
Off-Peak Variable Charge (per kWh)	TOUP2
Site Charge (per Day)	TOUP3
Demand Charge (per kW per Day)	TOUP4
Minimum Variable Charge (per Minimum kW per Day)	TOUP5
Power Factor Charge (per kVAr per Day)	TOUP6
Distribution Delivery Consumption Charge (per kWh)	D1

This rate is based on metering on the primary side of the transformer. Where secondary metering is installed, the meter readings shall be increased by 1.0% for transformer losses.

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

A Minimum Variable Charge applies to all sites. Minimum Variable Charge may be waived when a site was constructed for redundancy and the load exhibits absolute diversity.

Where the Power Factor is less than 90% during the interval of the peak daily demand, the Power Factor Charge shall apply.

The kVAr is the maximum kVAr, in excess of the kVAr at 90% power factor calculated for each interval during the billing period.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Commercial/Industrial Service Greater Than 5,000 kVA

Applicable: This rate is applicable to the Customer IDs listed below that registered a demand of greater than or equal to 5,000 kVA in the previous year.

Applicable: This rate is applicable to new sites forecast to have a normal maximum demand of greater than or equal to 5,000 kVA. These services are metered with an interval-recording meter. Each new site under this rate is required to enter into an Electric Service Agreement with EPCOR DISTRIBUTION.

Rate: **Distribution Access Charges**:

Customer ID (A Customer may have several sites)	Daily Distribution Access Charge Values (Refer to the values associated with the Cell References in the Attached Table 1)	Specific Distribution Loss Factors (Refer to the values associated with the Cell References in the Attached Table 1)
911xx	CS20	CS3
9016xx	CS21	CS4
Xxxxxx	CS22	CS5
881xx	CS23	CS6
8834xx	CS24	CS7
950xx	CS25	CS8
942xx	CS26	CS9
8838xx	CS27	CS10
955xx	CS28	CS11
9019xx	CS29	CS12
887xx	CS30	CS13
8832xx	CS31	CS14
880xx	CS32	CS15
141xxx	CS33	CS16
900xx	CS34	CS17
896xx	CS35	CS18
DCC	CS36	CS19

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
Distribution Delivery Consumption Charge (per kWh)	D1

Where an existing customer has multiple sites, the Daily Distribution Access Charge may, at EPCOR Distribution's discretion, be divided equally or in proportion to costs among those sites .

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Direct Connects to the Transmission System

Applicable: To all services that are connected directly to the provincial transmission system.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
Site Charge (per Day)	DC3
Distribution Delivery Consumption Charge (per kWh)	D1

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Street Lights

Applicable: To the Retailer for services owned by the City of Edmonton for Street Lighting Service.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	SL1
Off-Peak Variable Charge (per kWh)	SL2
Site Charge (per Day)	SL3
Minimum Variable Charge (per Minimum kW per Day)	SL10
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Traffic Control

Applicable: To the Retailer for services owned by the City of Edmonton for Traffic Lights and other Traffic Control Service.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	TL1
Off-Peak Variable Charge (per kWh)	TL2
Site Charge (per Day)	TL3
Minimum Variable Charge (per Minimum kW per Day)	TL10
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Lane Lights

Applicable: To the Retailer of the services owned by the City of Edmonton for Lane Lights Service.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	LL1
Off-Peak Variable Charge (per kWh)	LL2
Site Charge (per Day)	LL3
Minimum Variable Charge (per Minimum kW per Day)	LL10
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Security Lights

Applicable: To the Retailer of existing un-metered Security Light Service. This rate is not available to new services.

Rate: **Distribution Access Charges:**

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
On-Peak Variable Charge (per kWh)	SEL1
Off-Peak Variable Charge (per kWh)	SEL2
Site Charge (per Day)	SEL3
Minimum Variable Charge (per Minimum kW per Day)	SEL10
Distribution Delivery Consumption Charge (per kWh)	D1

Refer to the schedule titled "**Calculations of Demand and Minimum Variable Charges**" for calculation methodologies.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charge – Rate Schedule

Distribution Connected Generation

Applicable: To all Distribution Connected Generators. A bi-directional interval recording meter is required for each Distribution Connected Generation service.

Rate: **Distribution Access Charges:**
The Distribution Access Charges from the applicable Rate Schedule are applied to the absolute value of hourly energy as per customer meter. In addition to the regular Distribution Access Charges above, where EPCOR DISTRIBUTION provides primary metering and data transfer equipment, the additional charge is:

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 1)
Site Charge (per Day)	DGEN1

Distribution Access Charges – Rate Schedule

Unmetered Option

Applicable: To each service where energy consumption is small and can be easily predicted. The estimated consumption will be based on equipment nameplate rating and operational patterns. These services will be supplied under the Rate Schedule, Commercial/Industrial <50 kVA. EPCOR DISTRIBUTION reserves the right to audit and re-estimate energy consumption. The customer may provide an acceptable meter socket and request metered service.

Deemed energy consumption for common unmetered services are as follows: (note that this list of services and estimated daily consumptions are subject to updates)

Device	Estimated daily consumption kWh
Cable Television Signal Booster	10.0
Phone Booth 1 Lamp	2.5
Phone Booth 2 Lamp	5.0
Phone Booth 1 Lamp, 1 Sign	5.3
Phone Booth 2 Lamp, 1 Sign	8.8
Bus Shelter illuminated advertising	6.8
Airport "Caulder high line lights"	1.3
Airport Perimeter lights	25.5
City – China Gate	38.8
City – Drainage Flow Monitors (per location)	5.0
Rail Road Hazard Lights	2.7
CFB	650.0
Traffic Control Lights	See Traffic Control Detail Sheet
Controlled Street, Lane and Security Lights	See Lighting Detail Sheet
Charge Type	**Value (Refer to the values associated with the Cell References in the Attached Table 1)**
Distribution Delivery Consumption Charge (per kWh)	D1

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Access Charges – Rate Schedule

Franchise Fee

Applicable:	All services interconnected to EPCOR's distribution system and located within the City of Edmonton.
Rate:	EPCOR DISTRIBUTION will apply the Franchise Fee that the City of Edmonton directs EPCOR DISTRIBUTION to collect.

Distribution Tariff - 2001

Calculations of Demand and Minimum Variable Charges

The following words and phrases, whenever used in the Distribution Access rate schedules, shall be calculated in the manner set out below.

Billing Demand: Is the greater of Contracted Minimum Demand or Peak Monthly Demand in kW or kVA, subject to ratchets, that is applied to the Demand Charge in the rate schedules.

The Peak Monthly Demand is calculated as follows:

> *For Residential Services:* Total Settlement Load consumed in the last completed calendar month prior to the billing period in kWh / 182.50.
>
> *For Commercial/ Industrial Service <50 kVA*: Total Settlement Load consumed in the last completed calendar month prior to the billing period in kWh / 262.96.
>
> *For Commercial/ Industrial Service 50 kVA to <150 kVA:* Maximum monthly metered kVA in the last completed calendar month prior to the billing period.
>
> *For Commercial/ Industrial Service 150 kVA to <5,000 kVA*: Maximum metered kW in the last completed calendar month prior to the billing period.
>
> *For Street Lights Services:* Total Settlement Load consumed in the last completed calendar month prior to the billing period in kWh / 316.64
>
> *For Traffic Control Services:* Total Settlement Load consumed in the last completed calendar month prior to the billing period in kWh / 657.00
>
> *For Lane Lights Services:* Total Settlement Load consumed in the last completed calendar month prior to the billing period in kWh / 312.54.
>
> *For Security Lights Services:* Total Settlement Load consumed in the last completed calendar month prior to the billing period in kWh / 333.11.

The Billing Demand value shall be the greatest of:

i) The Peak Monthly Demand in the last completed calendar month prior to the billing period,
ii) 90% of the highest Peak Monthly Demand in the last 12 completed calendar months prior to the billing period,
iii) 85% of the highest Peak Monthly Demand in the last 24 completed calendar months prior to the billing period,

iv) 80% of the highest Peak Monthly Demand in the last 36 completed calendar months prior to the billing period,
v) 75% of the highest Peak Monthly Demand in the last 48 completed calendar months prior to the billing period,
vi) 70% of the highest Peak Monthly Demand in the last 60 completed calendar months prior to the billing period.

EPCOR DISTRIBUTION will only have 12 months of history starting January 1, 2001 for ratchet purposes and therefore, demand history will accumulate for the subsequent 48 months. On January 1 2005, 60 months of history will be accumulated, and thereafter, all data older than 60 months will no longer be used in the calculation of the ratchet.

Where historical demand data is expressed in kVA but kW data is required for the calculation of the demand ratchet, EPCOR distribution will estimate the kW value by multiplying the kVA value by a factor of 0.9.

Where historical demand data is expressed in kW but kVA data is required for the calculation of the demand ratchet, EPCOR distribution will estimate the kVA value by dividing the kW value by a factor of 0.9.

Contracted Minimum Demand: Is the demand level in kW or kVA established by contractual arrangement between EPCOR Distribution and the Authorized Person in relation to EPCOR's investment in site facilities.

Minimum Demand: Is calculated by multiplying the Billing Demand by a factor of 0.5. Minimum Demand is used in the calculation of the Minimum Variable Charge.

Minimum Variable Charge: Within the Distribution Access Service Charges, where the total On-Peak Variable Charge plus total Off-Peak Variable Charge for the billing period is less than the Minimum Variable Charge calculated, the Minimum Variable Charge shall apply.

The Minimum Variable Charge is calculated by multiplying the Minimum Demand (in kW or kVA) by the Minimum Variable Charge rate.

Normal Maximum Demand: The normal maximum demand is used to determine the type of meter used for a site and which rate schedule is applicable. The normal maximum demand may be measured as the peak demand over the last 12 months, or the forecast peak demand if EPCOR DISTRIBUTION deems that the past 12 months are not indicative of future load.

Peak Daily Demand: Is the highest demand in kW in an interval for interval metered customers during the day.

Peak Monthly Demand: Is the highest Peak 15 minute metered or estimated demand in a calendar month. This means the highest metered kW for interval metered sites, or the calculated kW for non-interval metered sites. The Peak Monthly Demand for sites with a kVA demand meter is determined by the last meter reading in the calendar month prior to the billing period.

Power Factor Charges: means the charges that apply to customers who have a Power Factor of less than 90% for the interval that is the Peak Daily Demand.

For example, a site has a Peak Daily Demand of 1,000 kW. During the same interval, the site registers 1,250 kVA. The Power Factor for the Peak Daily Demand is = 1,000/1,250 = 80%. Since the Power Factor is less than 90%, Power Factor Charges apply.

The calculation of kVAr is as follows: kVAr = SQRT (kVA^2 – kW^2).
The kVA at 90% Power Factor at 1,000 kW = 1,000/0.9 = 1,111 kVA
The kVAr at 90% Power Factor is equal to SQRT (1,111^2 – 1,000^2) = 484 kVAr.
The kVAr at 80% Power Factor is equal to SQRT (1,250^2 – 1,000^2) = 750 kVAr.
The kVAr applied to the Power Factor Charge = 750 kVAr – 484 kVAr = 266 kVAr.

Distribution Access Charges – Rate Schedule

Table 1: Values Referenced in Interim 2004 Distribution Tariff Rate Schedules
(Effective January 1, 2004)

Rate Class	Cell Reference	Value	Description
Residential	R1	$ 0.01200	/kWh of On-Peak Energy at the Meter
Residential	R2	$ 0.00158	/kWh of Off-Peak Energy at the Meter
Residential	R3	$ 0.28878	per site per day
Residential	R8	$ 0.03617	per Minumum kW per day Minimum Variable Charge
< 50kVA	SC1	$ 0.02381	/kWh of On-Peak Energy at the Meter
< 50kVA	SC2	$ 0.01301	/kWh of Off-Peak Energy at the Meter
< 50kVA	SC3	$ 0.16872	per site per day
< 50kVA	SC8	$ 0.05442	per Minumum kW per day Minimum Variable Charge
50 to 149 kVA	MC1	$ 0.01246	/kWh of On-Peak Energy at the Meter
50 to 149 kVA	MC2	$ 0.00163	/kWh of Off-Peak Energy at the Meter
50 to 149 kVA	MC3	$ 1.37279	per site per day
50 to 149 kVA	MC4	$ 0.04140	per kVA per Day
50 to 149 kVA	MC8	$ 0.05458	per Minumum kVA per day Minimum Variable Charge
150 to 4999 kW	TOU1	$ 0.01238	/kWh of On-Peak Energy at the Meter
150 to 4999 kW	TOU2	$ 0.00162	/kWh of Off-Peak Energy at the Meter
150 to 4999 kW	TOU3	$ 9.76375	per site per day
150 to 4999 kW	TOU4	$ 0.00498	per kW per Day
150 to 4999 kW	TOU5	$ 0.06861	per kW per Day of Minimum Charge
150 to 4999 kW	TOU6	$ 0.06509	per kVAr per Day of Power Factor Charge
Direct Connects to T.A.	DC3	$ 2.08780	per site per day
150 to 4999 kW - Primary	TOUP1	$ 0.01260	/kWh of On-Peak Energy at the Meter
150 to 4999 kW - Primary	TOUP2	$ 0.00165	/kWh of Off-Peak Energy at the Meter
150 to 4999 kW - Primary	TOUP3	$ 16.71640	per site per day
150 to 4999 kW - Primary	TOUP4	$ 0.00031	per kW per Day
150 to 4999 kW - Primary	TOUP5	$ 0.08097	per kW per Day of Minimum Charge
150 to 4999 kW - Primary	TOUP6	$ 0.06509	per kVAr per Day of Power Factor Charge
> 5000 kW - Primary	CS1	$ 2.08780	per customer per day for Wholesale Billing costs (ALL)
> 5000 kW - Primary	CS3	0.58%	Specific Distribution Loss Factor - 1 - 911xx
> 5000 kW - Primary	CS4	0.95%	Specific Distribution Loss Factor - 2 - 9016xx
> 5000 kW - Primary	CS5	0.83%	Specific Distribution Loss Factor - 4 - xxxxx
> 5000 kW - Primary	CS6	0.05%	Specific Distribution Loss Factor - 5 - 881xx
> 5000 kW - Primary	CS7	0.03%	Specific Distribution Loss Factor - 6 - 8834xx
> 5000 kW - Primary	CS8	0.30%	Specific Distribution Loss Factor - 8 - 950xx
> 5000 kW - Primary	CS9	0.43%	Specific Distribution Loss Factor - 9 - 942xx

Rate Class	Cell Reference	Value	Description
> 5000 kW - Primary	CS10	0.14%	Specific Distribution Loss Factor - 11 - 8838xx
> 5000 kW - Primary	CS11	0.38%	Specific Distribution Loss Factor - 13 - 955xx
> 5000 kW - Primary	CS12	0.34%	Specific Distribution Loss Factor - 15 - 9019xx
> 5000 kW - Primary	CS13	0.03%	Specific Distribution Loss Factor - 16 - 887xx
> 5000 kW - Primary	CS14	0.12%	Specific Distribution Loss Factor - 17 - 8832xx
> 5000 kW - Primary	CS15	0.16%	Specific Distribution Loss Factor - 18 - 880xx
> 5000 kW - Primary	CS16	1.34%	Specific Distribution Loss Factor - 20 - 141xxx
> 5000 kW - Primary	CS17	0.05%	Specific Distribution Loss Factor - 21 - 900xx
> 5000 kW - Primary	CS18	0.17%	Specific Distribution Loss Factor - 22 - 896xx
> 5000 kW - Primary	CS19	0.00%	Specific Distribution Loss Factor - 28 - DCC
> 5000 kW - Primary	CS19.1	0.07%	Specific Distribution Loss Factor - 29 -477xx
> 5000 kW - Primary	CS20	$ 184.01524	Daily Distribution Access Charge - 1 - 911xx
> 5000 kW - Primary	CS21	$ 1,135.64970	Daily Distribution Access Charge - 2 - 9016xx
> 5000 kW - Primary	CS22	$ 50.70282	Daily Distribution Access Charge - 4 - xxxxx
> 5000 kW - Primary	CS23	$ 292.21888	Daily Distribution Access Charge - 5 - 881xx
> 5000 kW - Primary	CS24	$ 207.00649	Daily Distribution Access Charge - 6 - 8834xx
> 5000 kW - Primary	CS25	$ 269.77855	Daily Distribution Access Charge - 8 - 950xx
> 5000 kW - Primary	CS26	$ 732.47779	Daily Distribution Access Charge - 9 - 942xx
> 5000 kW - Primary	CS27	$ 391.58899	Daily Distribution Access Charge - 11 - 8838xx
> 5000 kW - Primary	CS28	$ 699.37322	Daily Distribution Access Charge - 13 - 955xx
> 5000 kW - Primary	CS29	$ 315.70711	Daily Distribution Access Charge - 15 - 9019xx
> 5000 kW - Primary	CS30	$ 47.77901	Daily Distribution Access Charge - 16 - 887xx
> 5000 kW - Primary	CS31	$ 538.76072	Daily Distribution Access Charge - 17 - 8832xx
> 5000 kW - Primary	CS32	$ 294.31862	Daily Distribution Access Charge - 18 - 880xx
> 5000 kW - Primary	CS33	$ 354.06171	Daily Distribution Access Charge - 20 - 141xxx
> 5000 kW - Primary	CS34	$ 859.50098	Daily Distribution Access Charge - 21 - 900xx
> 5000 kW - Primary	CS35	$ 1,034.12256	Daily Distribution Access Charge - 22 - 896xx
> 5000 kW - Primary	CS37	$ 142.62073	Daily Distribution Access Charge - 29 - 477xx
Street Lights	SL1	$ 0.01875	/kWh of On-Peak Energy at the Meter
Street Lights	SL2	$ 0.00796	/kWh of Off-Peak Energy at the Meter
Street Lights	SL3	$ 0.11632	per site per day
Street Lights	SL10	$ 0.03832	per Minumum kW per day Minimum Variable Charge
Traffic Lights	TL1	$ 0.01550	/kWh of On-Peak Energy at the Meter
Traffic Lights	TL2	$ 0.00468	/kWh of Off-Peak Energy at the Meter
Traffic Lights	TL3	$ 0.09209	per site per day
Traffic Lights	TL10	$ 0.12196	per Minumum kW per day Minimum Variable Charge
Lane Lights	LL1	$ 0.01871	/kWh of On-Peak Energy at the Meter
Lane Lights	LL2	$ 0.00793	/kWh of Off-Peak Energy at the Meter
Lane Lights	LL3	$ 0.09209	per site per day
Lane Lights	LL10	$ 0.03780	per Minumum kW per day Minimum Variable Charge
Security Lights	SEL1	$ 0.07938	/kWh of On-Peak Energy at the Meter

Rate Class	Cell Reference	Value	Description
Security Lights	SEL2	$ 0.06842	/kWh of Off-Peak Energy at the Meter
Security Lights	SEL3	$ 0.09209	per site per day
Security Lights	SEL10	$ 0.04071	per Minumum kW per day Minimum Variable Charge
Distribution Connected Generator	DGEN1	$ 2.08637	per site per day

Distribution Delivery Consumption Charge rate per Kwh applicable to all rate classes	D1	$ 0.00018	/kWh of Total Energy at the Meter
Special Transmission Rider rate per Kwh applicable to all rate classes		$ (0.00027)	/kWh of Total Energy at the Meter

1. Schedule A: Standard Services Included in the Distribution Tariff

1.1 Metering Services

a) Regular Power Meter Reads

b) Off-cycle Meter Reads initiated by EPCOR Distribution

c) Standard Metering Report initiated by EPCOR Distribution

1.2 Settlement Services

a) Site Enrollment Request (SRR)

b) Site Enrollment Notification (SRN, SRO)

c) Settlement Results (WSI, SSI, SPI)

d) Settlement Diagnostic Reports required by Alberta Settlement System Code (e.g. UFE and loss statistics)

e) Cumulative Switch Estimates (CSE)

f) Missing Read Estimates (MRE) used in interim and final settlement

g) Site Characteristics Changes (PSC) e.g. profile class, loss class, seed consumption estimate, distribution tariff rate class attributes

1.3 Distribution and Transmission Tariff Services

a) Tariff Calculation Results Aggregated by Retailer

b) Provide Invoicing Details at Site Level

1.4 Distribution Operation Services

a) New Service Connection (install new meter)

b) Remove Pets from Poles

c) Construction for New Service

d) Consultation for Customer Energy Consumption Analysis (including High Consumption Complaints)

e) Reset Customer's Breaker

f) Diagnostic testing for Computer and Office Equipment Problem

g) Field Order Status

h) Open Transformer for Electrician to Pull in Secondary

i) De-Energize Primary for Electrician to Work on Main Service

j) Temporary Disconnection (at Meter) for Site Service

k) Investigate Power Quality Complaints

2. Schedule B: Standard Regulated Services Requested by Retailer

Value Associated with italicized references are contained in the attached Table 2.

2.1 Metering Services

a) Off-Cycle Meter Reads

- At least a 48 hours notice for the completion of such read is required. The charge for the Off-Cycle Meter Read is the value of *MMS-A1*.
- An Emergency Off-Cycle Meter Read is one which occurs when the retailer requests that the read be completed before the end of the normal period of notice (2 business days) required by EPCOR Distribution for the completion of such read. The charge for the Emergency Off-Cycle Meter Read is the value of *MMS-A2*.

b) Standard Metering Reports

- At least 10 working days of notice are required for the completion of a 12-month extraction of historical consumption data for a site. The charge for this service is the value of *MMS-B1*.

c) Ad-hoc Metering Reports

- This is a service provided to retailer at a negotiated price.
- The operator confirms feasibility of the request, according to the following criteria:
  1. Availability of data requested;
  2. Can the request be filled within ten days;
  3. Complexity of request requires negotiations.
- If the request is unfeasible, the operator rejects the request, and notifies the requesting party.

2.2 Settlement Services

a) Emergency Enrollment

- Process enrollment request within 24 hours to enable retailer to request energization of a site.
- Cost for providing the service is the value of *MSS-A1*.

b) Enrollment Inquiry (including error code inquiry)

- Telephone support for manual confirmation of enrollment, explanation of reasons for rejected enrollment request.
- Cost for providing the service is the value of *MSS-B1*.

c) Site Specific Settlement Results (DAS)

- Provide daily load settlement results for all sites enrolled by a retailer.
- Cost for providing the service the value of *MSS-C1*.

d) Settlement Diagnostic Report Not Required by Alberta Settlement System Code
  - Summary report relating to settlement operation or results for retailer's customers other than reports required by Alberta Settlement Code (e.g. site status report, settlement results changes).
  - Cost for providing the service is the value of *MSS-D1*.

e) Settlement Results Inquiry
  - Ad Hoc inquiry relating to settlement results or reproduction of results.
  - Cost for providing the service is the value of *MSS-E1*.

f) Retailer Provided Consumption Estimate
  - Retailer provided adjustment to EPCOR Distribution consumption estimate for a site.
  - Cost for providing the service is the value of *MSS-F1*.

g) Snapshot of Settlement Input Database for Retailer's Sites
  - Data dump of all inputs to settlement calculation for a given retailer's sites for a given period. Limited to past 12 months.
  - Cost for providing the service is the value of *MSS-G1*.

h) Re-run Settlement Requests
  - Request to re-run settlement results with specific parameters, e.g. request to correct slamming.
  - Cost for providing the service is the value of *MSS-H1*.

2.3 Distribution and Transmission Tariff Services

a) Ad-hoc Tariff Requests
  - Inquires from external requestors (e.g. Retailers, Market Surveillance Administrator, etc.) regarding explanation of tariff charges, error codes, billing determinants used and resulting charges, and any other inquiries relating to distribution and transmission tariff calculations.
  - Cost for providing the service is the value of *MDTS-A1*.

b) Re-creation of Specific Tariff Run
  - Upon request and pending availability of the Settlement/Tariff operational window, specific tariff run may be re-created. Settlement date, stage (initial, interim and final), and sites must be specified at the time of the request.
  - Cost for providing the service is the value of *MDTS-B1*.

c) Tariff Charges Aggregated by Wires Rate Class (includes count of sites)
  - Upon request, a report will be prepared using pre-defined, standard format. Costing will be based on the single tariff run (e.g., initial run for January 5th)
  - Cost for providing the service is the value of *MDTS-C1*.

Note: Recreation of historical data is limited to the latest 12-month period available.

2.4 Distribution Operation Services

a) Emergency Service Connection

- An Emergency Service Connection (including a physical turn on of an existing service or a new meter installation) is a service which occurs when the retailer requests that the connection be completed before the end of the normal period of notice (2 business days) required by EPCOR Distribution for the completion of such service.
- Emergency Meter Installation
  - a) Single Phase Installation (apartment etc.) *MDOS-1A*
  - b) Underground Installation *MDOS-1B*
  - c) Overhead Installation *MDOS-1C*
  - d) Open Wire Installation *MDOS-1D*
  - e) Quaroplex Installation *MDOS-1E*
  - f) Farm Installation *MDOS-1F*
  - g) Network Customer Installation *MDOS-1G*
  - h) Polyphase Energy Installation *MDOS-1H*
  - i) Self Contained Polyphase Installation *MDOS-1I*
- Emergency Unseal Meter *MDOS-1-1*
- Emergency Meter and Aerial Service Installation up to 200 amps *MDOS-1-2*
- Emergency Meter and U/G Service Installation up to 200 amps *MDOS-1-3*
- Emergency Meter and Service Installation Over 200 amps, Plus the Cost of Installing the Emergency Service
  - a) TX Rated Secondary Demand Installation *MDOS-1-4*
  - b) TX Rated Primary Demand Installation *MDOS-1-5*

b) Temporary Set Up of Power Service

- Where a separate temporary power is provided for construction Purposes in addition to the construction cost to supply the service *MDOS-2-1*

c) De-Energize Service (including the sealing of a meter or disconnecting a service at the pole) *MDOS-3-1*

d) Install/Remove Current Limiter

- Where the weather does not permit for a service disconnection, a current limiter will be installed *MDOS-4-1*

e) Remove Meter and Service *MDOS-5-1*

f) Upgrade to an Interval Meter

- A retailer who has a customer with demand threshold below 150 kVa and requests EPCOR Distribution to install an interval meter is liable for the cost of the meter that exceeds the cost recoverable under the distribution tariff *MDOS-6-1*

g) Perform Meter Check/Testing
   - If the result of the meter check indicates the meter is functioning within the parameters defined by the Electricity and Gas Inspection Act, the customer is liable for the cost of the meter check *MDOS-7-1*
   - If the meter is proven to be malfunction, the customer's meter reading will be adjusted and no cost to the customer for the meter check *MDOS-7-2*

h) Upgrade Security Light Equipment *MDOS-8-1*

3. Schedule C: Standard Regulated Services Requestable by Any Party

Values Associated with italicized references are contained in the attached Table 2.

3.1 Distribution Operation Services

a) Tree Guards

- The fee for installation of tree guards on a customer's service wire shall be:

For the first tree guard	*MDOS-CA1*
For each addition guard installed at the same time and location	*MDOS-CA2*

4. Schedule D: Negotiated Regulated Services Requestable by Any Party

4.1 Distribution Operation Services

a) Provide High Voltage Insulation for Contractors to Hang Signs

b) Re-route Line for Contractors

c) Network or Primary Switching

d) Terminate Transformers for Land Developer (Underground Residential)

e) Escort High Loads

f) Trouble Calls

g) System Damage Reports

h) Jobbing Requests

5. Schedule E: Services and Charges Initiated by EPCOR Distribution

Values Associated with italicized references are contained in the attached Table 2.

5.1 Settlement Services

a) Customer Information Breach Fee

- The Retailer is required to advise EPCOR Distribution, within 2 business days, of any changes in customer information as defined by the UCI (Update Customer Information) transaction in the Alberta Settlement System Code. If the Retailer, at any time, fails to provide the information in the specified time frame, the Retailer will pay EPCOR Distribution a Customer Information Breach Fee of *MSS-I1*

5.2 Distribution Operation Services

a) Meter Tampering

- The repair fee charged to a customer whose meter has been tampered with, disconnected or has had the seal broken shall be charged for re-installing or re-sealing and adjusting the meter reading. In addition to the above fee, if applicable, the cost of a new meter and a fine of not more than $500.00 may be assessed against the unauthorized persons who have tampered with or disconnected the meter, or broken the seal *MDOS-EBI*

5.3 Financial Services

a) Returned Cheque Fee

- EPCOR Distribution Will assess a returned cheque fee to any customer/Retailer whose cheque made payable to EPCOR Distribution is dishonored by any bank when presented for payment by EPCOR Distribution *MFS-E1*

6. Schedule F: Non-Regulated Services

6.1 Metering Services

a) Sub-Metering Service

6.2 Distribution Operation Services

a) Support Poles During Excavation (install new water, sewer or gas lines)

b) Provide Contractors Specialized Equipment

c) Change Light Bulbs (Commonwealth Stadium, John Ducey, etc.)

d) Set Poles for Contractors

e) Pull in Secondary Cables for Contractors

f) Build Transformer Pads for Contractors

g) Fiber-optic Cable Installation

h) Hydrovacing

i) Specialized Cable Work (Lead Cable)

j) Locate Underground Secondary Fault to Service on Private Property

Table 2: Values Referenced in Schedule of Miscellaneous Services

Rate Class	Cell Reference	Value	Description	Services
	MMS-A1	$6.50 per site	Off-Cycle Meter Reads	Metering Services
	MMS-A2	$9.00 per site	Emergency Off-Cycle Meter Read	Metering Services
	MMS-B1	$25.00 per site	Standard Metering Reports	Metering Services
	MSS-A1	$9.00 per site	Emergency Enrollment	Settlement Services
	MSS-B1	$10.00 per inquiry plus $100.00 per hour	Enrollment Inquiry (including error code inquiry)	Settlement Services
	MSS-C1	$0.01 per site per month	Site Specific Settlement Results	Settlement Services
	MSS-D1	$100.00 per report	Settlement Diagnostic Report Not Required by Alberta Settlement System Code	Settlement Services
	MSS-E1	$20.00 per inquiry plus $100.00 per hour	Settlement Results Inquiry	Settlement Services
	MSS-F1	$50.00 per estimate adjustment	Retailer provided site consumption estimate	Settlement Services
	MSS-G1	$0.01 per site per day	Snapshot of Settlement Input Database for Retailer's Sites	Settlement Services
	MSS-H1	$1000.00 per run plus $200.00 per hour	Re-run Settlement Request	Settlement Services
	MSS-I1	$50.00 per site	Customer Information Breach Fee	Settlement Services
	MDTS-A1	$20.00 per inquiry plus $100.00 per hour	Ad-hoc Tariff Requests	Distribution and Transmission Tariff Services
	MDTS-B1	$1000.00 per run plus $200.00 per hour	Re-creation of Specific Tariff Run	Distribution and Transmission Tariff Services
	MDTS-C1	$20.00 per report	Tariff Charges Aggregated by Wires Rate Class (includes count of sites)	Distribution and Transmission Tariff Services
	MDOS-1A	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Single Phase	Distribution Operation Services
	MDOS-1B	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Underground	Distribution Operation Services

Rate Class	Cell Reference	Value	Description	Services
	MDOS-1C	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Overhead	Distribution Operation Services
	MDOS-1D	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Open Wire	Distribution Operation Services
	MDOS-1E	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Quaroplex	Distribution Operation Services
	MDOS-1F	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Farm	Distribution Operation Services
	MDOS-1G	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Network Customer	Distribution Operation Services
	MDOS-1H	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Polyphase Energy	Distribution Operation Services
	MDOS-1I	$24.00 plus standard connection fee of $22.00	Emergency Meter Installation - Self Contained Polyphase	Distribution Operation Services
	MDOS-1-1	$24.00 plus standard connection fee of $22.00	Emergency Unseal Meter	Distribution Operation Services
	MDOS-1-2	$135.00 plus standard connection fee of $22.00	Emergency Meter and Aerial Service Installation up to 200 amps	Distribution Operation Services
	MDOS-1-3	$77.00 plus standard connection fee of $22.00	Emergency Meter and Underground Service Installation up to 200 amps	Distribution Operation Services
	MDOS-1-4	$24.00 plus the cost of installing the emergency service	Emergency Meter and Service Installation Over 200 amps, Plus the Cost of Installing the Emergency Service - TX Rated Secondary Demand Installation	Distribution Operation Services
	MDOS-1-5	$24.00 plus the cost of installing the emergency service	Emergency Meter and Service Installation Over 200 amps, Plus the Cost of Installing the Emergency Service - TX Rated Primary Demand Installation	Distribution Operation Services
	MDOS-2-1	$180.00 plus the construction cost to supply the service	Temporary Set Up of Power Service	Distribution Operation Services

Rate Class	Cell Reference	Value	Description	Services
	MDOS-3-1	No Charge	De-Energize Service (including the sealing of a meter or disconnecting a service at the pole)	Distribution Operation Services
	MDOS-4-1	No Charge	Install/Remove Current Limiter	Distribution Operation Services
	MDOS-5-1	No Charge	Remove Meter and Service	Distribution Operation Services
	MDOS-6-1	$3630.00	Upgrade to an Interval Meter	Distribution Operation Services
	MDOS-7-1	At Customer's Cost	Perform Meter Check/Testing and Meter Proves Functioning	Distribution Operation Services
	MDOS-7-2	No Charge	Perform Meter Check/Testing and Meter Proves Unfunctioning	Distribution Operation Services
	MDOS-8-1	At Customer's Cost	Upgrade Security Light Equipment	Distribution Operation Services
	MDOS-CA1	$58.00	Tree Guards for first tree guard	Distribution Operation Services
	MDOS-CA2	$26.00	Tree Guards for each addition guard installed at the same time and location	Distribution Operation Services
	MDOS-EB1	$55.00	Metering Tampering	Distribution Operation Services
	MFS-E1	$20.00	Returned Cheque Fee	Financial Services

SCHEDULE B-EDI SAS PRICE SCHEDULES

EDI SAS Tariff
Schedule 2

(Consists of 24 pages)

EPCOR

DT- Schedule 2

Transmission System Access Tariff
(Interim 2004)

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System Access Service Charges – Rate Schedule

Residential Service
Commercial/Industrial Service < 50 kVA
Commercial/Industrial Service 50 kVA to 149 kVA
Commercial/Industrial Service 150 to 5,000 kVA
Primary Commercial/Industrial Service 150 to 5,000kVA
Commercial/Industrial Service Greater Than 5,000 kVA
Direct Connects to the Transmission System
Street Lights
Traffic Control
Lane Lights
Security Lights

Rate: **System Access Service Charges:**

The Alberta Electric System Operator (AESO) Transmission Tariff is applied to each customer's contribution to energy and demand at the transmission point of delivery (POD). Load Settlement determines the customer's contribution to energy and demand at the POD. A management fee is applied to cover the cost of managing the AESO invoice and rebilling.

The Terms and Conditions and the Franchise Fee apply to all customers.

System Access Service Charges – Rate Schedule

Deferral Account

Rate: System Access Service Charge Deferral Account:

EPCOR Distribution will track the total annual cost of providing System Access Service to EPCOR Distribution's interface point. The total cost of service includes;

a) the AESO's transmission charges,
b) Aquila Networks Canada's charges in lieu of AESO charges at the 25 kV interchange points,
c) the cost of administration for rebilling System Access Service Charges.

EPCOR Distribution will also track the total revenue from System Access Service Charges. Once each year, EPCOR Distribution will reconcile the difference between costs and revenue for System Access Service charges and charge/refund the difference on a $/KWh basis to all customers connected to EPCOR Distribution's system.

The Terms and Conditions and the Franchise Fee apply to all customers.

System Access Service Charges – Application Guide

Residential Service, Commercial/Industrial Service < 50 kVA, and Commercial/Industrial Service 50 kVA to Less Than 150 kVA

Applicable: To all residential services that are served by EPCOR and which have an energy meter. Residential Service is only available to single or two family dwellings consisting of a suite of rooms provided with sleeping and cooking facilities, which is being used primarily for domestic use. Where a business is conducted from a dwelling that it is also used for domestic purposes, the Residential Service is no longer applicable if the service is larger than 200 amps.

The intent is that this rate is applicable for residential services that are on average 600 kWh per month, typically share a 37 or 50 kVA transformer with about 12 other residential services and some streetlights. Residential sites may be eligible for Commercial Service only if the service is not typical of a residential service and at least one of the following parameters are met:

a) The service panel is larger than 200 amps,
b) The site does not share a transformer.

Only very small, low energy consumption services receive a lower bill under the commercial rate. Small residences or low energy consumption residences do not qualify for Small Commercial Service.

Applicable: This rate is applicable to services that have a normal maximum demand of less than 50 kVA. These services normally have energy meters only with the exception of those services that qualify for the Unmetered Option. This rate is also applicable to all services for which no other rate is applicable.

The normal maximum demand is the peak demand over the last 12 months, or the forecast peak demand if EPCOR has reason to believe that the historic load is not indicative of future load. Whenever facilities are installed to supply a site with more than 50 kVA, a flag should be raised for a person to assess if this service should be changed to the next larger rate class. If warranted, a different meter should be installed and the site should be invoiced on the new appropriate rate.

Applicable: This rate is applicable to services that have a normal maximum demand of greater than or equal to 50 kVA and less than 150 kVA. These services normally have demand meters.

The normal maximum demand is the peak demand over the last 12 months, or the forecast peak demand if EPCOR has reason to believe that the past 12 months are not indicative of future load. Whenever a site on this rate has a meter reading over 150 kVA, or has 12 consecutive months of meter readings below 50 kVA, a flag should be raised for a person to assess if this service should be changed to another rate class. If warranted, a different meter should be installed and the site should be invoiced on the new appropriate rate.

Rate: **System Access Service Charges:**

The AESO's Transmission Tariff is applied to each site's contribution to energy and demand at the AESO's aggregate POD level. Settlement will provide each sites contribution to energy at the aggregate POD level. Settlement will take into consideration the NSLS, the energy consumption at the site, the distribution line losses and UFE.

The Billing Demand for System Access Service Charges is the demand coincident to the TA POD peak. The Billing Demand and the Peak Monthly Demand are calculated and defined as shown in the Definition of Billing Demand.

The Peak Monthly Demand may vary as long as Settlement data is subject to change.

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 3)
Conversion kW @ site to kW Coincident to POD Peak	SASR-1
Demand Charge ($/kW/day)	SASR-2
Other System Support Charge ($/kW/Day)	SASR-5
Variable Charge ($/kWh)	SASR-3
Pool Price Charge (Variable Charge)	SASR-4

The Demand Charge is calculated as follows:

Demand Charge =
*SASR-2** X
Billing Demand

The Other System Support Charge is calculated as follows:

Other System Support Charge =
*SASR-5** X
Peak Monthly Demand

The Variable Charge is calculated as follows:

Variable Charge =
*SASR-3** X
Energy Delivered in the billing period as per Settlement.

The Pool Price Charge is applied to the energy delivered during the billing period (as per Settlement). The Pool Price Charge is calculated as follows:

Pool Price Charge =
kWh as per Settlement during each hour X *SASR-4**
X Applicable Pool Price during each hour.

The same billing process is used for the Initial Settlement, the Interim Settlement and the Final Settlement.

The Terms and Conditions of the AESO apply.

The Terms and Conditions and the Franchise Fee apply to all sites.

* The italicized codes will have an associated value in the attached Table 3.

System Access Service Charges – Application Guide

Primary and Secondary Commercial/Industrial Service 150 kVA to 5,000 kVA, Connected to EPCOR's Distribution System

Applicable: This rate is applicable to sites that have a normal maximum demand of greater than or equal to 150 kVA and less than 5,000 kVA and connected to EPCOR's distribution system. These services require an interval-recording meter. This rate is applicable to all services that are served at the secondary voltage of the transformer, normally with a delivery voltage of below 1,000 volts as well as those services connected at the primary side of the transformer, normally with a delivery voltage of over 1,000 volts.

Rate: **System Access Service Charges:**

The AESO's Transmission Tariff is applied to each site's contribution to energy and demand at the AESO's aggregate POD level. Settlement will provide each sites contribution to energy and demand at the aggregate POD level. Settlement will take into consideration the energy consumption at the site, the distribution line losses and UFE.

The Peak Monthly demand is based on the highest 15-minute meter interval during the complete month.

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 3)
Diversity Factor	SASCI-1
Line Loss Factor	SASCI-2
Demand Charge ($/kW/day)	SASCI-3
Other System Support Charge ($/kW/Day)	SASCI-6
Variable Charge ($/kWh)	SASCI-4
Pool Price Charge (Variable Charge)	SASCI-5

The Demand Charge is calculated as follows:

Demand Charge =
*SASCI-3**
X Billing Demand

The Other System Support Charge is calculated as follows:

Other System Support Charge =
*SASCI-6** X
Peak Monthly Demand

The Variable Charge is calculated as follows:

Variable Charge =
*SASCI-4** X
Energy delivered in the billing period as per Settlement.

The Pool Price Charge is applied to the energy consumption during the billing period (as per Settlement). The Pool Price Charge is calculated as follows:

Pool Price Charge =
*SASCI-5** X
Energy delivered as per Settlement during each hour X
Applicable Pool Price each hour .

The same billing process is used for the Initial Settlement, the Interim Settlement and the Final Settlement.

The Terms and Conditions of the AESO apply.

The Terms and Conditions and the Franchise Fee apply to all sites.

* The italicized codes will have an associated value in the attached Table 3.

System Access Service Charges – Application Guide

Primary and Secondary Commercial/Industrial Service Greater than 5,000 kVA, Connected to EPCOR's Distribution System

Applicable: This rate is applicable to sites that have a normal maximum demand of greater than 5,000 kVA and connected to EPCOR's distribution system. These services require an interval-recording meter. This rate is applicable to all services that are served at the secondary voltage of the transformer, normally with a delivery voltage of below 1,000 volts as well as those services connected at the primary side of the transformer, normally with a delivery voltage of over 1,000 volts.

Rate: **System Access Service Charges:**

The AESO's Transmission Tariff is applied to each site's contribution to energy and demand at the AESO's aggregate POD. Settlement will provide each sites contribution to energy and demand at the aggregate POD level. Settlement will take into consideration the energy consumption at the site, the distribution line losses and UFE.

The Peak Monthly demand is based on the highest 15-minute meter interval during the complete month.

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 3)
Diversity Factor	SASCS-1
Line Loss Factor	SASCS-2
Demand Charge ($/kW/day)	SASCS-3
Other System Support Charge ($/kW/Day)	SASCS-6
Variable Charge ($/kWh)	SASCS-4
Pool Price Charge (Variable Charge)	SASCS-5

Please refer to DT Schedule 1, Distribution Access Charges – Rate Schedule, Commercial/Industrial Service Greater Than 5,000 kVA, for a listing of customers and their Line Loss Factor.

The Demand Charge is calculated as follows:

Demand Charge =
*SASCS-3**
X Billing Demand

The Other System Support Charge is calculated as follows:

Other System Support Charge =
*SASCS-6** X
Peak Monthly Demand

The Variable Charge is calculated as follows:

Variable Charge =
*SASCS-4** X
Energy delivered in the billing period as per Settlement.

The Pool Price Charge is applied to the energy consumption during the billing period (as per Settlement). The Pool Price Charge is calculated as follows:

Pool Price Charge =
*SASCS-5** X
Energy Delivered as per Settlement during each hour X
Applicable Pool Price each hour .

The same billing process is used for the Initial Settlement, the Interim Settlement and the Final Settlement.

The Terms and Conditions of the AESO apply.

The Terms and Conditions and the Franchise Fee apply to all sites.

* The italicized codes will have an associated value in the attached Table 3.

System Access Service Charges – Application Guide

Direct Connects to the Transmission System

Applicable: To all services that are connected directly to the provincial transmission system.

Rate: **System Access Service Charges:**

The AESO's Transmission Tariff is applied to each site's contribution to energy and demand at the AESO's aggregate POD level. Settlement determines each sites contribution to energy and demand at the POD. No distribution losses are considered in Settlement for direct connected sites.

The Peak Monthly demand is based on the highest 15-minute meter interval during the complete month.

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 3)
Diversity Factor	SASDC-1
Line Loss Factor	SASDC-2
Demand Charge ($/kW/day)	SASDC-3
Other System Support Charge ($/kW/Day)	SASDC-8
Variable Charge ($/kWh)	SASDC-4
Pool Price Charge (Variable Charge)	SASDC-5
Power Factor Charge ($/kVAr/day)	SASDC-6
TA Management Fee	SASDC-7

The Demand Charge is calculated as follows:

Demand Charge =
*SASDC-3** X
Billing Demand

The Other System Support Charge is calculated as follows:

Other System Support Charge =
*SASDC-8** X
Peak Monthly Demand

The Variable Charge is calculated as follows:

Variable Charge =
*SASDC-4** Variable Charge ($/kWh) X
Energy delivered in the billing period as per Settlement.

The Pool Price Charge is applied to the energy consumption during the billing period (as per Settlement). The Pool Price Charge is calculated as follows:

Pool Price Charge =
*SASDC-5** X
Energy delivered as per Settlement during each hour X
Applicable Pool Price each hour .

The Power Factor Charge applies if the Power Factor is less than 90% during the Peak Monthly Demand.

Prior to the Interim and Final Settlement invoices, the AESO's invoice is received, reconciliation with the AESO's Transmission Tariff is required. The Transmission Administrator invoices on a monthly basis while EPCOR invoices on a daily basis.

Interim and Final Settlement involves a comparison of the AESO's invoice (plus Management Fee) for the month to the sum of the initial System Access Service bills. The TA Management Fee consists of a charge as per *SASDC-7**.

The Interim bill will include a credit (or charge) to reconcile the sum of the amount paid in Initial bills with the AESO's invoice for the POD plus the TA Management Fee.

The final bill will include a credit (or charge) to reconcile the amount paid in the interim bill with the AESO's invoice for the POD plus the TA Management Fee.

The Terms and Conditions of the Transmission Administrator apply.

The Terms and Conditions and the Franchise Fee apply to all sites.

* The italicized codes will have an associated value in the attached Table 3.

System Access Service Charges – Application Guide

Photo Eye Operated Load

Applicable: To the Retailer for services owned by the City of Edmonton for Street Lighting Service.

Applicable: To the Retailer for services owned by the City of Edmonton for Lane Lights Service.

Applicable: To the Retailer for existing unmetered Security Light Service. This rate is not available to new services.

Rate: **System Access Service Charges:**

The AESO's Transmission Tariff is applied to each site's contribution to energy at the AESO's aggregate POD level. Settlement will provide each sites contribution to energy at the aggregate POD level. Settlement will take into consideration the appropriate load profile, the energy consumption at the site, the distribution line losses and UFE.

The Billing Demand for System Access Service Charges is the demand coincident to the AESO POD peak. The Billing Demand and the Peak Monthly Demand are calculated and defined as shown in the Definition of Billing Demand.

The Peak Monthly Demand may vary as long as Settlement data is subject to change.

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 3)
Conversion kW @ site to kW Coincident to POD Peak	SASPE-1
Demand Charge ($/kW/day)	SASPE-2
Other System Support Charge ($/kW/Day)	SASPE-5
Variable Charge ($/kWh)	SASPE-3
Pool Price Charge (Variable Charge)	SASPE-4

The Demand Charge is calculated as follows:

Demand Charge =
*SASPE-2**
X Billing Demand

The Other System Support Charge is calculated as follows:

Other System Support Charge =
*SASPE-5** X
Peak Monthly Demand

The Variable Charge is calculated as follows:

Variable Charge =
*SASPE-3** X
Energy delivered in the billing period as per Settlement.

The Pool Price Charge is applied to the energy consumption during the billing period (as per Settlement). The Pool Price Charge is calculated as follows:

Pool Price Charge =
*SASPE-4** X
Energy delivered as per Settlement during each hour X
Applicable Pool Price during each hour.

The same billing process is used for the Initial Settlement, the Interim Settlement and the Final Settlement.

The Terms and Conditions of the AESO apply.

The Terms and Conditions and the Franchise Fee apply to all sites.

* The italicized codes will have an associated value in the attached Table 3.

System Access Service Charges – Application Guide

Continuous Operation Load

Applicable: To the Retailer for services owned by the City of Edmonton for Traffic Lights and other Traffic Control Service.

Rate: **System Access Service Charges:**

The AESO's Transmission Tariff is applied to each site's contribution to energy and demand at the AESO's aggregate POD level. Settlement will provide each sites contribution to energy at the aggregate POD level. Settlement will take into consideration the appropriate load profile, the energy consumption at the site, the distribution line losses and UFE.

The Billing Demand for System Access Service Charges is the demand coincident to the AESO POD peak. The Billing Demand and the Peak Monthly Demand are calculated and defined as shown in the Definition of Billing Demand.

The Peak Monthly Demand may vary as long as Settlement data is subject to change.

Charge Type	Value (Refer to the values associated with the Cell References in the Attached Table 3)
Conversion kW @ site to kW Coincident to POD Peak	SASCO-1
Demand Charge ($/kW/day)	SASCO-2
Other System Support Charge ($/kW/Day)	SASCO-5
Variable Charge ($/kWh)	SASCO-3
Pool Price Charge (Variable Charge)	SASCO-4

The Demand Charge is calculated as follows:

Demand Charge =
*SASCO-2** X
Billing Demand

The Other System Support Charge is calculated as follows:

Other System Support Charge =
*SASCO-5** X
Peak Monthly Demand

The Variable Charge is calculated as follows:

Variable Charge =
*SASCO-3** X
Energy delivered in the billing period as per Settlement.

The Pool Price Charge is applied to the energy consumption during the billing period (as per Settlement). The Pool Price Charge is calculated as follows:

Pool Price Charge =
*SASCO-4** X
Energy delivered as per Settlement during each hour X
Applicable Pool Price during each hour.

The same billing process is used for the Initial Settlement, the Interim Settlement and the Final Settlement.

The Terms and Conditions of the AESO apply.

The Terms and Conditions and the Franchise Fee apply to all sites.

* The italicized codes will have an associated value in the attached Table 3.

System Access Service Charges – Application Guide

Distribution Connected Generation

Applicable: To each service where generation exceeds the on-site load and energy is exported back to the distribution system. A bi-directional interval recording meter is required for each Distribution Connected Generation service.

Rate: **System Access Service Charges:**
Any credits received from the AESO as a result of the operation of distribution-connected generation will be passed on directly to the generator.

The Terms and Conditions and the Franchise Fee apply to all sites.

Distribution Tariff – Application Guide

Franchise Fee

Applicable:	All sites interconnected to EPCOR's distribution system and located within the City of Edmonton.
Rate:	EPCOR will apply the Franchise Fee that the City of Edmonton directs EPCOR to collect.

Distribution Tariff – Application Guide

Definition of Billing Demand

Applicable: All sites.

The Billing Demand is the greatest of:

i) The Peak Monthly Demand in the last completed month prior to the billing period,
ii) 90% of the highest Peak Monthly Demand in the last 12 completed calendar months,
iii) 85% of the highest Peak Monthly Demand in the last 24 completed calendar months,
iv) 80% of the highest Peak Monthly Demand in the last 36 completed calendar months,
v) 75% of the highest Peak Monthly Demand in the last 48 completed calendar months,
vi) 70% of the highest Peak Monthly Demand in the last 60 completed calendar months.

EPCOR will only have 48 months of history starting January 1, 2004 for ratchet purposes and therefore, demand history will accumulate for the following 12 months. On January 1 2005, 60 months of history will be accumulated, and thereafter, all data older than 60 months will no longer be required (assuming that the Transmission Administrator has a 60-month ratchet in effect at that time).

Peak Monthly Demand: means the peak demand in kW that a site contributes to the coincident peak at the AESO POD.

For sites with out an interval-recording meter, the Peak Monthly Demand for System Access Service Charges is equal to the site peak (Peak Monthly Demand for Distribution Access Service Charges) multiplied by the Conversion factor listed under each customer group. When Peak Monthly Demand for Distribution Access Service Charges is expressed in kVA, a conversion factor of 0.92 shall be used to convert the kVA to kW.

For sites with an interval-recording meter, the Peak Monthly Demand is calculated as follows:

$$\text{Peak Monthly Demand} = \text{highest 15 minute interval (kW)} \times \text{Diversity Factor} \times (1 + \text{Line Loss Factor})$$

Table 3: Values Referenced in 2004 System Access Service Rate Schedules

Rate Class	Cell Reference	Value	Description
Residential, Commercial/ Industrial Service <50 kVA, Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SASR-1	49.45%	Conversion kW @ site to kW at Coincident POD peak
Residential, Commercial/ Industrial Service <50 kVA, Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SASR-2	$ 0.04408	/kW/day of Demand Charge
Residential, Commercial/ Industrial Service <50 kVA, Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SASR-3	$ 0.0018806	/ kWh of Energy Charge
Residential, Commercial/ Industrial Service <50 kVA, Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SASR-4	3.75%	Pool Price Charge (Total Energy)
Residential, Commercial/ Industrial Service <50 kVA, Commercial/ Industrial Service 50 kVA to Less Than 150 kVA	SASR-5	$ 0.00070	/kW/day of Other System Support Charge
150 to 5000 kVA	SASCI-1	61.23%	Diversity Factor
150 to 5000 kVA	SASCI-2	3.68%	Line Loss Factor
150 to 5000 kVA	SASCI-3	$ 0.04408	/kW/day of Demand Charge
150 to 5000 kVA	SASCI-4	$ 0.0018806	/ kWh of Energy Charge
150 to 5000 kVA	SASCI-5	3.75%	Pool Price Charge (Total Energy)
150 to 5000 kVA	SASCI-6	$ 0.00070	/kW/day of Other System Support Charge
> 5000 kVA	SASCS-1	85.41%	Diversity Factor
> 5000 kVA	SASCS-2	Refer to DAC	Line Loss Factor Varies by Customer, Please refer to Distribution Access
> 5000 kVA	SASCS-3	$ 0.04408	/kW/day of Demand Charge
> 5000 kVA	SASCS-4	$ 0.0018806	/ kWh of Energy Charge
> 5000 kVA	SASCS-5	3.75%	Pool Price Charge (Total Energy)
> 5000 kVA	SASCS-6	$ 0.00070	/kW/day of Other System Support Charge
Direct Connects to T.A.	SASDC-1	100.00%	Diversity Factor
Direct Connects to T.A.	SASDC-2	0.00%	Line Loss Factor
Direct Connects to T.A.	SASDC-3	$ 0.04408	/kW/day of Demand Charge
Direct Connects to T.A.	SASDC-4	$ 0.0018806	/ kWh of Energy Charge
Direct Connects to T.A.	SASDC-5	3.75%	Pool Price Charge (Total Energy)
Direct Connects to T.A.	SASDC-6	$ 0.06247	/kVAr of Power Factor Charge
Direct Connects to T.A.	SASDC-7	$ 0.05060	/MWh of TA management fee
Direct Connects to T.A.	SASDC-8	$ 0.00070	/kW/day of Other System Support Charge

Rate Class	Cell Reference	Value	Description
Photo Eye	SASPE-1	92.5%	Conversion kW @ site to kW at Coincident POD peak
Photo Eye	SASPE-2	$ 0.04408	/kW/day of Demand Charge
Photo Eye	SASPE-3	$ 0.0018806	/ kWh of Energy Charge
Photo Eye	SASPE-4	3.75%	Pool Price Charge (Total Energy)
Photo Eye	SASPE-5	$ 0.00070	/kW/day of Demand Charge
Continous Operating Load	SASCO-1	92.5%	Conversion kW @ site to kW at Coincident POD peak
Continous Operating Load	SASCO-2	$ 0.04408	/kW/day of Demand Charge
Continous Operating Load	SASCO-3	$ 0.0018806	/ kWh of Energy Charge
Continous Operating Load	SASCO-4	3.75%	Pool Price Charge (Total Energy)
Continous Operating Load	SASCO-5	$ 0.00070	/kW/day of Other System Support Charge

Distribution Tariff – Application Guide

Appendix A

Examples for a One Day Billing Period

Res, Com, Ind < 150 kVA	Cust Demand* (kW) @ site Meter	Daily Energy (kWh) @ POD	Conversion kW @ site to coin POD pk kW	Forecast Average Pool Price ($/MWh)	Demand Charge $/kW/day	Energy Charge $/MWh	Percent Coeff	Daily Bill
Demand Charge	2.76	20.00	49.45%		$0.04408			$0.060
Energy Charge	2.76	20.00				$1.8806		$0.038
Pool Price Charge	2.76	20.00		$47.00			3.75%	$0.035
Other System Support Charge	2.76	20.00	49.45%		$0.00070			$0.001
Sub-Total	* Determined through Conversion							**$0.134**

150 kVA to 5,000 kVA	Cust Dem (kW) @ POD	Daily Energy (kWh) @ POD	Diversity Factor	Forecast Average Pool Price ($/MWh) Line Loss Factor	Demand Charge $/kW/day	Energy Charge $/MWh	Percent Coeff	Daily Bill
Demand Charge	500	6,250	61.23%	3.68%	$0.04408			$13.50
Energy Charge	500	6,250				$1.8806		$11.75
Pool Price Charge	500	6,250		$47.00			3.75%	$11.02
Other System Support Charge	500	6,250	61.23%	3.68%	$0.00070			$0.21
Sub-Total	TA POD Demand is Customer Demand X (1+Loss Factor) X Diversity							**$36.48**

Customer Specific	Cust Dem (kW) @ POD	Daily Energy (kWh) @ POD	Diversity Factor	Forecast Average Pool Price ($/MWh) Line Loss Factor	Demand Charge $/kW/day	Energy Charge $/MWh	Percent Coeff	Daily Bill
Demand Charge	15,000	324,000	85.41%	0.26%	$0.04408			$564.73
Energy Charge	15,000	324,000				$1.8806		$609.31
Pool Price Charge	15,000	324,000		$47.00			3.75%	$571.05
Other System Support Charge	15,000	324,000	85.41%	0.26%	$0.00070			$8.97
Sub-Total	TA POD Demand is Customer Demand X (1+Loss Factor) X Diversity							**$1,754.06**

Direct Connects	Cust Dem (kW)	Daily Energy (kWh) @ POD	Diversity Factor	Forecast Average Pool Price ($/MWh) Line Loss Factor	Demand Charge $/kW/day	Energy Charge $/MWh	Percent Coeff	Daily Bill
Demand Charge	15,000	324,000	100.00%	0.00%	$0.04408			$661.20
Energy Charge	15,000	324,000				$1.8806		$609.31
Pool Price Charge	15,000	324,000		$47.00			3.75%	$571.05
Other System Support Charge	15,000	324,000	100.00%	0.00%	$0.00070			$10.50
Sub-Total	TA POD Demand is Customer Demand X (1+Loss Factor) X Diversity							**$1,852.06**

Night Lighting	Cust Demand* (kW) @ site Meter	Daily Energy (kWh) @ POD	Conversion to kW @POD Pk	Forecast Average Pool Price ($/MWh)	Demand Charge $/kW/day	Energy Charge $/MWh	Percent Coeff	Daily Bill
Demand Charge	0.485	5.3	92.5%		$0.04408			$0.02
Energy Charge	0.485	5.3				$1.8806		$0.01
Pool Price Charge	0.485	5.3		$47.00			3.75%	$0.01
Other System Support Charge	0.485	5.3	92.5%		$0.00070			$0.00
Sub-Total	* Determined through Conversion							**$0.04**

Continuous Lighting (Traffic)	Cust Demand* (kW) @ site Meter	Daily Energy (kWh) @ POD	Conversion to kW @POD Pk	Forecast Average Pool Price ($/MWh)	Demand Charge $/kW/day	Energy Charge $/MWh	Percent Coeff	Daily Bill
Demand Charge	1.061	24	92.50%		$0.04408			$0.04
Energy Charge	1.061	24				$1.8806		$0.05
Pool Price Charge	1.061	24		$47.00			3.75%	$0.04
Other System Support Charge	1.061	24	92.5%		$0.00070			$0.00
Sub-Total	* Determined through Conversion							**$0.13**

Customer Demand for non interval meter customers is done in 3 groups, less than 150 kVA, Photo Eye Operated, and Continuous Operation

SCHEDULE C-EDI DISTRIBUTION SERVICE CONNECTIONS TERMS AND

EDI Distribution
Access Service T&C

(Consists of 28 pages)

TERMS AND CONDITIONS
FOR
DISTRIBUTION ACCESS SERVICE

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ARTICLE 1 –INTRODUCTION TO TERMS AND CONDITIONS

These Terms and Conditions, as approved by the Alberta Energy and Utilities Board (the "Board"), form part of the Distribution Tariff of EPCOR Distribution Inc. ("EDI") and are established pursuant to section 102 of the *Electric Utilities Act 2003*, c. E-5.1. The Distribution Tariff is available for public inspection during normal business hours at the business offices of EDI and can be accessed on EDI's web site at:

www.epcor.ca/EPCOR+Companies/EPCOR+Distribution+and+Transmission/default.htm

These Terms and Conditions apply to EDI and its relationship with Retailers. All Retailers by virtue of their relationship with EDI are deemed to have accepted these Terms and Conditions.

The service provided by EDI hereunder is regulated by the Board and parties having any inquiries or complaints regarding these Terms and Conditions may direct such inquiries or complaints directly to EDI or to the Board.

No agreement can provide for the waiver or alteration of any part of these Terms and Conditions unless such agreement is first filed with and approved by the Board. Whenever the Board approves an amendment to these Terms and Conditions, such amendment, including its effective date, will be posted on EDI's website at:

www.epcor.ca/EPCOR+Companies/EPCOR+Distribution+and+Transmission/default.htm

ARTICLE 2 – DEFINITIONS AND INTERPRETATION

2.1 Definitions

The following words and phrases, whenever used in these Terms and Conditions or in an application, contract or agreement for service under these Terms and Conditions, shall have the meanings set forth below:

"**Act**" means the *Electric Utilities Act*, S.A. 2003, c. E-5.1, as re-enacted, amended or replaced from time to time;

"**Board**" or "**EUB**" means the Alberta Energy and Utilities Board established under the *Alberta Energy and Utilities Board Act*, R.S.A., 2000, c. A-17, as re-enacted, amended or replaced from time to time;

"**Business Day**" means a business day is any day other than Saturday, Sunday or a holiday as defined in the *Interpretation Act*, R.S.A. 2000, c. I-8, as re-enacted, amended or replaced from time to time;

"**Credit Rating**" has the meaning given to it in the Distribution Tariff Regulation;

“**Customer**” means a person purchasing electricity for that person's own use from a Retailer;

“**Customer Information**” means Customer name, Customer telephone number, Customer mailing address, site contact name and site contact phone number and other Customer information that may be requested by EDI;

“**Customer Usage Information**” means information regarding the historical electricity consumption of a Customer;

“**De-energization**” has the meaning attributed to it in the Settlement System Code and “**De-energized**” and “**De-energize**” have correlative meanings;

“**Default Supplier**” means a Retailer appointed by EDI pursuant to section 3 of the RRR Regulation;

“**Distribution Access Service**” has the meaning given to it in the Act;

“**Distribution Services Agreement**” means an agreement between EDI and a Retailer for the provision of the applicable Distribution Access Service;

“**Distribution Tariff**” means a distribution tariff prepared by EDI and approved by the Board in accordance with section 102 of the Act;

“**Distribution Tariff Regulation**” means the *Distribution Tariff Regulation*, A.R. 162/2003, as amended from time to time;

“**Distribution Tariff Services**” means all services provided by EDI under the Distribution Tariff;

“**EDI**” or “**EPCOR Distribution**” means EPCOR Distribution Inc. or its successor;

“**Electricity Services**” means the services associated with the provision of electricity to a person, including the exchange of electric energy, making financial arrangements to manage financial risk associated with the pool price, Distribution Access Service, system access service, ancillary services, billing, metering, performing load settlement and any other services specified in regulations made under the Act;

“**Energy**” means electric energy (expressed in kilowatt hours);

“**Energization**” has the meaning attributed to it in the Settlement System Code

"**Facilities**" means physical plant (including, without limitation, distribution lines, transformers, meters, equipment, machinery and other electrical apparatus) on EDI's side of the Point of Service interconnection excluding transmission facilities;

"**Fee Schedule**" means the fees and charges set forth in Table 2 of Schedule A - DAT Rate and Fee Schedule to EDI's Distribution Tariff;

"**Force Majeure**" means circumstances not reasonably within the control of EDI, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, mechanical breakdowns, the intervention of federal, provincial, state or local government or from any of their agencies or boards, the order or direction of any court, and any other cause, whether of the kind herein enumerated or otherwise;

"**Independent System Operator**" or "**ISO**" means the corporation established by section 7 of the Act;

"**Interconnected Electric System**" means all transmission facilities and electric distribution systems in Alberta that are interconnected;

"**Load Settlement**" means "load settlement" as defined in the Act.

"**Minimum Charge**" has the meaning given to it in EDI's Terms and Conditions for Distribution Connection Services;

"**Miscellaneous Services**" means the various services available from EDI under the Distribution Tariff other than Distribution Access Service;

"**Point of Service**" means the point at which EDI's service conductors are connected to the conductors or apparatus of a Customer;

"**Power Pool**" means the scheme operated by the Independent System Operator for the exchange of Energy and financial settlement for the exchange of Energy;

"**Rate Schedules**" means the schedules of EDI's Distribution Tariff that set out charges;

"**RRR Regulation**" means the *Roles, Relationships and Responsibilities Regulation*, A.R. 169/2003, as amended from time to time;

"**Regulations**" means regulations made under the Act;

"**RDS Regulation**" means the *Regulated Default Supply Regulation*, A.R. 168/2003, as amended from time to time;

"**Regulated Rate Tariff**" means a regulated rate tariff for the provision of Electricity Services to eligible customers prepared by EDI, or a person with whom EDI makes arrangements to do so, pursuant to section 102 of the Act;

"**Retailer**" means a person who sells or provides Electricity Services directly to Customers and carries out the functions and duties of a "retailer" under the Act, and includes a Default Supplier, the person with whom EDI has made arrangements to provide the Regulated Rate Tariff to eligible customers, and Self-Retailers;

"**Retailer Handbook**" means the guide, as amended from time to time, prepared by EDI which sets out procedures in relation to the provision of Distribution Access Service under these Terms and Conditions.

"**Retailer Identification**" means the 10 digit number that uniquely represents each Retailer operating within Alberta. The Canada Customs and Revenue Agency business number will be used as the Retailer ID;

"**Retailer of Record**" means the Retailer who is listed in EDI's records through the procedures outlined in these Terms and Conditions, and thereby recognized by EDI and the Settlement System Code, as a particular Customer's Retailer for a Point of Service at a particular time;

"**Self-Retailer**" means a person carrying out Retailer functions to obtain electricity services solely for its own use;

"**Service Connection**" means the Facilities required to physically connect the Customer's facilities to EDI's electric distribution system to permit the Customer to obtain Distribution Access Service;

"**Settlement System Code**" means the rules respecting Load Settlement established by the Independent System Operator pursuant to the Act;

"**Site**" means a unique end-use Point of Service, being the finest level at which Load Settlement recognizes Retailer assignments, and receives consumption data.

2.2 Conflicts

If there is any conflict between a provision expressly set out in an order of the Board and these Terms and Conditions, the order of the Board shall govern.

If there is any conflict between a provision in these Terms and Conditions, as may be amended from time to time, and a provision in a Distribution Services Agreement or any other existing or future agreement between EDI and a Retailer relating to Distribution Tariff Services, the provision in these Terms and Conditions shall govern.

2.3 Extended Meanings

In these Terms and Conditions, words importing the singular number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neutral genders and vice versa. Word importing a person shall include person, firm, partnership, corporation, organization or association (including, without limitation, individual members of any unincorporated entity).

2.4 Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

ARTICLE 3 – GENERAL PROVISIONS

3.1 Retailer Handbook

EDI has developed the Retailer Handbook to help Retailers understand the normal practices of EDI. EDI will amend the Retailer Handbook, from time to time, to reflect changes to the electric utility industry, changes in EDI's requirements or the changing needs of Retailers or Customers. While EDI will endeavour to follow practices in the Retailer Handbook, these practices will not appropriately cover every situation that may arise and its may be necessary to deviate from the Retailer Handbook. A copy of the Retailer Handbook can be accessed on EDI's website at www.epcor.ca.

3.2 Arrangements with Customers

The Retailer shall be solely responsible for having appropriate contractual or other arrangements with Customers necessary to provide service to Customers. EDI shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements and shall not be liable for any loss, damages, cost, injury, expense or other liability, whether direct, indirect, consequential or special in nature, howsoever caused, as a result of the Retailer's failure to obtain or maintain proper contractual or other arrangements with Customers or to perform its obligations to its Customers.

3.3 Responsibility for Electric Purchases

The Retailer will be solely responsible for the purchase of electricity from the Power Pool and for arranging the delivery of such electricity to the appropriate Points of Service for Customers, subject to these Terms and Conditions.

3.4 Retailer Authorization

A Retailer shall be responsible for obtaining proper authorization from each Customer authorizing the enrollment of the Customer by the Retailer for receipt of Distribution Access Service.

3.5 Retailer Identification

Any information exchange or communications between the Retailer and EDI under these Terms and Conditions shall employ a Retailer Identification number.

3.6 Single Retailer for Customer

EDI shall not be required to recognize and deal with more than one Retailer in respect of a Point of Service at any given time.

3.7 Fees and Other Charges

EDI will provide all standard services hereunder pursuant to the Distribution Tariff. All additional, supplementary or extra non-discretionary services provided by EDI to a Retailer or its Customers will be charged a separate rate or fee, such as those included, without limitation, in the Fee Schedule. Payment for these services shall be in accordance with the provisions of these Terms and Conditions.

ARTICLE 4 – CUSTOMER INQUIRIES AND INFORMATION

4.1 Customer Inquiries Related to Emergency Situations and Outages

Retailers shall make every effort to ensure Customers contacting the Retailer regarding distribution emergency conditions, outages, safety or environment situations related to EDI's electric distribution system are referred directly to EDI immediately. EDI reserves the right, without providing notice to the Retailer, to test or audit the response time of the Retailer. EDI will communicate any unacceptable patterns to the Retailer to be corrected.

4.2 Exchange of Customer Information

4.2.1 Provision of Customer Information to a Retailer

EDI shall provide standard Customer Usage Information to a Retailer that has a Distribution Service Agreement in place with EDI, upon request, but only after receiving written consent to such disclosure from the Customer, for the 12-month period preceding the date of the request or for such shorter period for which EDI has collected that information.

Prior to requesting EDI to release Customer Usage Information, a Retailer shall be responsible for obtaining and providing to EDI the written authorization from the Customer referred to above, in a form satisfactory to EDI.

Customer Usage Information, including both cumulative and interval meter data, will be provided by EDI. EDI charges a fee as set forth in the Fee Schedule for providing such information.

4.2.2 Provision of Customer Information to EDI

The Retailer must notify EDI, as promptly as reasonably practical, of any changes to Customer Information in respect of its Customers. Such information shall be provided in a form satisfactory to EDI.

4.2.3 Provision of Information between EDI and Retailer

EDI and a Retailer shall supply to each other all other data, materials or other information specified to be supplied in the Terms and Conditions, or that may otherwise be reasonably required by the Retailer or EDI in accordance with the Terms and Conditions. See the Fee Schedule for charges that will apply to certain requests made to EDI.

ARTICLE 5 – PROVISION OF SERVICE

5.1 Qualification for Service

A Retailer must fulfill and maintain the following requirements to the satisfaction of EDI before EDI will provide or continue to provide Distribution Access Service to that Retailer:

(a) submit to EDI a fully completed and executed Distribution Service Agreement;

(b) if the Retailer sells Electricity to Customers whose annual consumption is below 250,000 kWh, furnish to EDI a certified copy of the license issued to the Retailer and warrant in writing to EDI that it is licensed pursuant to the provisions of the *Fair Trading Act Fair Trading Act*, R.S.A. 2000, c. F-2, and any regulations or policies made thereunder, as amended from time to time,

(d) satisfy the credit requirements described in Article 9 hereof;

(e) warrant in writing to EDI that it will comply with the Settlement System Code;

(f) meet the compliance testing protocol of EDI in respect of information exchange as set forth in the Retailer Handbook, as amended from time to time; and

(g) warrant in writing to EDI that it has been qualified by the ISO as pool participant under the ISO rules respecting the operation of the Power Pool and the ISO has approved the Retailer for consumption within the EDI service area; and

(h) meet any other requirements that EDI, acting reasonably, may impose in order to provide Distribution Access Service hereunder to the Retailer. If EDI determines that a Retailer must satisfy additional requirements in order to qualify for Distribution Access Service, EDI shall apply to the Board for approval of the proposed additional requirements prior to implementing same unless EDI is confronted with a situation that may materially alter the risk to EDI or the additional requirements are required to comply with applicable legislation. In that event, EDI may implement the additional requirements and then apply to the Board for approval of same; or

Upon satisfaction of the above requirements, EDI will provide Distribution Access Service to the Retailer, upon and subject to these Terms and Conditions. Subject to complying with all applicable laws, and the directions or requirements of the Board, EDI reserves the right, upon giving the Retailer ten (10) Business Days notice and acting reasonably, to discontinue Distribution Access Service to the Retailer if at any time the Retailer fails to meet the above requirements.

5.2 Application for Enrollment of Customers of Retailer

In order to initiate the provision of Distribution Access Service by EDI, the Retailer shall complete and provide to EDI an enrollment for Distribution Access Service in accordance with the Retailer Handbook and in compliance with the Settlement System Code.

EDI will, subject to these Terms and Conditions, accept an application by a Retailer for provision of Distribution Access Service to a Customer hereunder and recognize the Retailer as the Retailer of Record for the particular Customer. EDI reserves the right, but is not obligated, to verify the identity of the Customer and the accuracy of the Customer Information. EDI may reject the application if any information required in the application, including the Customer Information and Retailer Identification, provided by the Retailer is false, incomplete or inaccurate in any respect.

Enrollments will be processed by EDI on a first-come, first-served basis. Each enrollment will be time and date-stamped when received by EDI. If more than one enrollment is received for a Site while an earlier enrollment is pending, only the first valid enrollment received by EDI shall be processed that day.

EDI reserves the right to refuse Distribution Access Service at any Site to any Customer of the Retailer who is indebted to EDI. The Retailer will not be liable to EDI for any outstanding indebtedness of the Customer to EDI, which accrued prior to the enrollment of the Customer with the Retailer. However, the Retailer will be liable for all outstanding indebtedness while the Retailer remains the Retailer of Record for the Customer.

EDI may assess a charge for processing an enrollment as set forth in the Fee Schedule.

5.3 De-enrollment as Retailer

To de-enroll as Retailer of Record for a particular Customer, a Retailer shall, at least seven (7) Business Days (or such other time as may be required under the System Settlement Code) before the de-enrolment is to take effect, complete and provide to EDI a notice of de-enrolment pursuant to the Settlement System Code. EDI may reject the notice of de-enrolment if EDI determines that any information required in the notice, including Customer Information, provided by the Retailer is false, incomplete or inaccurate in any respect. EDI reserves the right, but is not obligated, to verify the identity of the Customer and the accuracy of the Customer Information. Upon receipt of a notice of de-enrolment from a Retailer, EDI will either:

(a) process the de-enrolment within seven (7) Business Days (or such other time as may be required under the System Settlement Code); or

(b) notify the Retailer within two (2) Business Days (or such other time as may be required under the System Settlement Code) that the notice of de-enrolment has been rejected and the reasons for such rejection. Upon receipt of a rectified notice of de-enrolment, EDI will, within seven (7) Business Days (or such other time as may be required under the System Settlement Code), process the de-enrolment.

ARTICLE 6 – BILLING AND PAYMENT

6.1 Billing

EDI will bill Retailers the amounts payable for Distribution Tariff Services in accordance with these Terms and Conditions and the *Billing Regulation, 2003*, A.R. 159/2003, as amended from time to time.

EDI will bill the Retailer each billing cycle for Distribution Access Service and Miscellaneous Services provided by EDI in relation to Customers for which the Retailer is the Retailer of Record for the period prior to the billing period.

EDI will not assume any billing or collection obligations or responsibilities related to billing Customers or collecting from Customers for, or on behalf of, a Retailer. The Retailer shall process Customer payments and handle collection responsibilities. EDI may, at its sole discretion and in addition to any other remedies available to it, terminate Distribution Tariff Services to the Retailer, if such Retailer does not pay all outstanding bills in accordance with these Terms and Conditions.

EDI reserves the right to bill the Customer directly for any amounts required to be provided by the Customer under the Terms and Conditions for Distribution Connection Services.

6.2 Determination of Applicable Rates

EDI bills the Retailer of Record based on the charges set out in its Rate Schedules in the Distribution Tariff. EDI's Rate Schedules indicate to what type of service each Rate Schedule applies. Each Point of Service is billed as a separate service. EDI's Distribution Tariff policies from time to time including its policies for Distribution Assess Tariff Treatment of Standby Services, Transmission Access Tariff Treatment of Standby Services, Applicability of Existing Site Demand Ratchets to New Customers and

Totalization of Transmission Demand as amended from time to time will apply to the determination of the charges.

The rate selection criteria are specified on each Rate Schedule. If the operational characteristics of the Point of Service change and subsequently a different rate is applicable, the Customer may be required to pay an additional Customer Contribution under the Terms and Conditions for Distribution Connection Services. A change of service under this section will not be made more than once in any twelve (12) month period.

6. 3 Minimum Charges

A Minimum Charge will be calculated in accordance with the Rate Schedules.

6. 4 Consumption Period

The basis of all charges to the Retailer for Distribution Access Service provided to a Customer is the consumption period, defined as the time between two consecutive meter readings, or estimates thereof, for the Customer's Site, unless otherwise indicated in the applicable Rate Schedules. For each Customer, basic monthly and capacity charges are prorated over the consumption period using the following formulas:

(a) basic monthly charge × days in consumption period × 12 ÷ 365 (or 366 in a leap year)

(b) charge per unit × capacity units × days in consumption period × 12 ÷ 365 (or 366 in a leap year)

For newly connected services, the first consumption period begins on the earlier of the date the service was connected or thirty (30) days from when the service was made available to the Customer.

6. 5 Billing Period and Information for Distribution Access Service

The billing period for the Retailer in respect of Distribution Access Service is generally the calendar week directly preceding the week in which the associated bill is issued to the Retailer. The amount charged to the Retailer for the billing period reflects the aggregate of charges for Distribution Access Service provided to Customers of the Retailer, with consumption periods that end within the billing period.

A bill to the Retailer for Distribution Access Service will set out the following information with respect to the billing period for which the bill is rendered:

(a) the total amount due from the Retailer for Distribution Access Service provided by EDI to Customers of the Retailer;

(b) details of the amount due from the Retailer for Distribution Access Service provided by EDI as applicable to each of the Retailer's Customers; and

(c) any other information required to be provided by EDI to the Retailer on a bill pursuant to the Act and Regulations.

6. 6 Billing Period and Information for Miscellaneous Services

The billing period for the Retailer in respect of Miscellaneous Services is generally the calendar month directly preceding the month in which the associated bill is issued to the Retailer. The amount charged to the Retailer for the billing period reflects the aggregate of charges for Miscellaneous Services provided to the Retailer within the billing period.

A bill to the Retailer for Miscellaneous Services will set out the following information with respect to the billing period for which the bill is rendered:

(a) the total amount due from the Retailer for Miscellaneous Services provided by EDI to the Retailer;

(b) any other information required to be provided by EDI to the Retailer on a bill pursuant to the Act and Regulations.

6.7 Payment and Collection

The Retailer shall pay to EDI, on or before the (fifth) 5th Business Day following the Business Day on which the Retailer was invoiced for Distribution Access Service and on or before the (twentieth) 20th Business Day following the Business Day on which the Retailer was invoiced for Miscellaneous Services, the amount invoiced by EDI for the preceding period.

EDI will establish an electronic billing and payment procedure for the payment of services hereunder. Notwithstanding such procedure, EDI will accept payment by cash or cheque if agreed to by EDI. A bill will be deemed to have been paid when a valid payment has been received by EDI for the full amount of the bill by way of cheque or electronic fund transfer.

Should the Retailer dispute any amount owing, the Retailer shall nonetheless pay such disputed amount and subject the dispute for resolution in accordance with these Terms and Conditions. Following resolution of any such dispute, EDI will return any amount found owing to the Retailer forthwith. Subject to the RDS Regulation, the right or ability of either EDI or a Retailer to dispute a bill provided hereunder shall only apply to bills rendered during a period of twelve (12) months prior to the date that the disputing party first gives notice of such dispute to the non-disputing party.

The Retailer shall pay all amounts owed to EDI for any of the Distribution Access Service provided by EDI whether or not the Customer has paid the Retailer.

Failure to receive a bill in a timely way does not release a Retailer from the obligation to pay the amount owing on the bill.

6.8 Late or Unpaid Bills

If a Retailer defaults or is late in paying charges, EDI shall access a late payment fee of 1% of the amount of a weekly bill and 2% per month (26.82% per annum) of the amount on monthly bills.

6.9 Adjustment of Bills in Event of Billing Error

Where EDI overcharges or undercharges on a bill as a result of a billing error including, but not limited to, incorrect meter reads or any calculation, rate application or clerical errors, EDI shall render an adjusted bill for the amount of the undercharge, without interest, and shall issue a refund or credit to the Retailer for the amount of the overcharge, without interest, in accordance with the following procedures:

(a) If a Retailer is found to have been overcharged due to billing error, EDI will calculate the amount of the overcharge (for refund to the Retailer on the Retailer's next bill following the discovery of the billing error) for those billing periods during which a billing error occurred up to a maximum of twelve (12) months immediately preceding the month in which the billing error was discovered. However, if the period of billing error cannot be determined with reasonable accuracy, the overcharge will be calculated for the three (3) month period immediately preceding the month in which the billing error was discovered.

(b) If a Retailer is found to have been undercharged due to billing error, subject to the RDS Regulation, EDI will bill the Retailer for those billing periods during which a billing error occurred up to a maximum of twelve (12) months immediately preceding the month in which the billing error was discovered. However, if the period of billing error cannot be determined with reasonable accuracy, the undercharge will be calculated for the three (3) months period immediately preceding the month in which the billing error was discovered.

Whenever EDI adjusts any bills to the Retailer in the event of billing error, and issues an adjusted bill or a refund or credit to the Retailer in respect thereof, the Retailer shall be responsible for adjusting bills and issuing refunds or credits as appropriate to the affected Customers.

EDI may assess a charge to the Retailer for reviewing billing as set forth in the Fee Schedule, where EDI has not been responsible for any billing error.

6.10 Unauthorized Use

Where EDI determines that there has been unauthorized use of electric service by a Customer of a Retailer including, but not limited to, meter tampering, unauthorized connection or reconnection, theft or fraud whereby EDI is denied full compensation for Distribution Access Service provided, EDI will bill the Retailer for EDI's estimate of such unauthorized use. Nothing in this Section shall limit any other rights or remedies that EDI may have in connection with such unauthorized use.

ARTICLE 7 – DISCONTINUANCE OF DISTRIBUTION ACCESS SERVICE

7.1 Discontinuance at Request of Customer

Customers arrange termination of Distribution Access Service through their Retailer of Record. If Distribution Access Service is no longer required, the Retailer of Record must notify EDI at least five (5) Business Days before the service is to be discontinued.

7.2 Discontinuance by De-energization

A Retailer may request that EDI De-energize a Site. To discontinue Distribution Access Service through De-energization, a Retailer shall, at least five (5) Business Days (or such other time as may be required under the System Settlement Code) before the site is to be De-energized, complete and provide to EDI a notice of De-energization pursuant to the requirements of the Retailer Handbook and the Settlement System Code. Such notice of De-energization shall clearly specify the Retailer's reasons for seeking to De-energize a site.

EDI reserves the right, but is not obligated, to verify the identity of the Customer of the Retailer pursuant to which De-energization has been requested, and the accuracy of the Customer Information that has been provided by the Retailer.

Upon receipt of such notice, EDI will either:

(a) process the De-energization within five (5) Business Days (or such other time as may be required under the System Settlement Code); or

(b) notify the Retailer within two (2) Business Days (or such other time as may be required under the System Settlement Code) that the notice of De-energization has been rejected and the reasons for such rejection. Upon receipt of the rectified notice of De-energization, EDI will, within five (5) Business Days (or such other time as may be required under the System Settlement Code), process the De-energization.

Notwithstanding the foregoing:

(c) EDI may reject the notice of De-energization if EDI, acting reasonably, determines that any information required in the application, including the Customer Information provided by the Retailer, is false, incomplete or inaccurate in any respect;

(d) EDI will not process a De-energization if EDI believes De-energization could cause any actual or threatened danger to life or property; and

(e) at the request of the Retailer or the Customer, EDI will leave all of its Facilities in place after the Point of Service has been de-energized provided that, if the Point of Service remains de-energized for a period in excess of three (3) months, EDI may remove its Facilities.

Upon De-energization, the Retailer will remain as the Customer's Retailer of Record unless a De-Select Request is submitted by the Retailer to EDI and successfully completed the process.

The Retailer is responsible to ensure that its Customer is provided notice of a De-energization and for the consequences of the De-energization. EDI will have no liability for any disputes between the Customer and the Retailer in relation to an De-energization.

7.3 Discontinuance by EDI

EDI may discontinue Distribution Access Service to a Retailer if any of the following occur:

(a) if the Retailer sells Electricity to Customers whose annual consumption is below 250,000 kWh, the Retailer's license issued pursuant to the *Fair Trading Act*, , R.S.A. 2000, c. F-2, has been revoked or not renewed, or

(b) the Retailer has failed to meet its obligations under these Terms and Conditions or its Distribution Services Agreement with EDI, or

(c) the Retailer has failed to meet its security requirements pursuant to Article 8

Notification of discontinuance will be made electronically to the Retailer.

ARTICLE 8 – SECURITY REQUIREMENTS

8.1 Security

The Retailer must fulfill the requirements as set forth in this Article 8 to the satisfaction of EDI before EDI will provide Distribution Access Service to that Retailer.

The Retailer shall provide the security deposit required under the Distribution Tariff Regulation to ensure that the Retailer is and remains of sufficient financial standing to meet its ongoing financial obligations.

The Retailer's application to EDI for service under the Distribution Tariff must include the Retailer's projected value of its payments to EDI under EDI's Distribution Tariff over the period provided in section 8 of the Distribution Tariff, the Retailer's current Credit Rating, if it is seeking a reduction in its security deposit, and the current Credit Rating of any proposed guarantors, if the Retailer's security deposit will include a guarantee.

For the purposes of projecting the Retailer's payments under EDI's Distribution Tariff pursuant to section 8(2)(b) of Distribution Tariff Regulation the total of:

(a) twenty (20) days; plus

(b) the number of days between consecutive bills issued by EDI to the Retailer; plus

(c) the number of days from the issuance of a bill by EDI until payment is due from the Retailer;

shall equal thirty-four (34) days.

EDI will confirm the Credit Rating of the Retailer, if provided, and the Credit Rating of any guarantor, if any, providing a guarantee as a security deposit. If the Retailer or guarantor has obtained more than one Credit Rating, the lowest Credit Rating will be used in the assessment.

EDI, subject to review and assessment, shall confirm the amount of security required to be provided by the Retailer, taking into account any reduction that the Retailer may be entitled to under section 9 of the Distribution Tariff Regulation and notify the Retailer of its security requirement within twenty (20) Business Days of the Retailer's complete application for Distribution Access Service.

Subject to section 9 of the Distribution Tariff Regulation, the Retailer shall provide security in the form of a financial deposit, a bond, an irrevocable letter of credit or an irrevocable guarantee from a person, other than the Retailer, with a Credit Rating, or a combination thereof, in each case in a form acceptable to EDI.

8.2 Maintenance of Security

If a Retailer's actual outstanding charges under EDI's Distribution Tariff are materially greater than the project of value provided by the Retailer under Section 8.1 of these Terms and Conditions, EDI will update the projection and, if additional security is required based on the updated projection, require the Retailer to provide additional security. The Retailer must provide the additional security within five (5) Business Days of EDI's request to do so.

A Retailer whose security deposit has been reduced pursuant to the Distribution Tariff Regulation by virtue of its Credit Rating shall report to EDI any downgrading of its Credit Rating within two (2) Business Days of the downgrading and must provide any additional security required as a result of the downgrading within five (5) Business Days of the downgrading.

If the Retailer fails to provide any additional security that it is required to provide, EDI reserves the right to suspend the provision of additional Distribution Access Service until the Retailer provided EDI with the required security.

A Retailer must maintain the required amount of security deposit until all obligations of the Retailer under EDI's Distribution Tariff are satisfied.

8.3 Use of Security

If a Retailer defaults in paying any amounts owing under EDI's Distribution Tariff, EDI will provide the Retailer notice as required by section 12 of the Distribution Tariff Regulation and will be entitled to draw on the security deposit of the Retailer to recover the Retailer's arrears including any accrued interest if they are not paid within three (3) Business Days after the date of the notice, provided that EDI shall be entitled to draw on the security deposit without notice if, in the opinion of EDI, the giving of such notice would impair EDI's ability to make a claim against the Retailer's security or to deduct the unpaid arrears from the Retailer's financial deposit. EDI may require additional security to replace the security drawn down because of the default by the Retailer. The Retailer must provide the additional security within five (5) Business Days of EDI's request to do so.

8.4 Suspension of Service

If the Retailer fails to provide any security that it is required to provide under this Article 8, EDI reserves the right to suspend the provision of additional Distribution Access Service until the Retailer provides EDI with the required security.

8.5 Costs of Security

All costs associated with the provisions of the security required to be provided by a Retailer for its obligations under EDI's Distribution Tariff are the responsibility of the Retailer.

ARTICLE 9 – METERING

9.1 Meter Reading

EDI shall make an actual meter reading for each Point of Service for which it provides Distribution Access Service for Customers of the Retailer in accordance with EDI's meter reading schedule. At the request of a Retailer of Record, EDI shall make an actual meter reading, off-cycle, as may be requested by the Retailer and EDI will charge the Retailer for additional meter reading expense as set forth in the Fee Schedule.

9.2 Record

An accurate record of meter readings will be kept by EDI which will be the basis for billing by EDI to the Retailer in accordance with the Distribution Tariff.

9.3 Estimated Consumption and Demand

The amount of energy used by a Customer will be estimated by EDI based on the best available sources of information and evidence in the following circumstances:

(a) where the Customer's Point of Service is not metered;

(b) where a meter is inaccessible due to conditions on the Customer's premises;

(c) where the meter is not scheduled to be read;

(d) where it is determined that the amount of energy used was different from that recorded or billed due to incorrect billing procedures;

(e) where a meter reading schedule or a meter change creates a transition period in EDI's billing cycle; or

(f) if the seal of a meter is broken or if the meter does not register correctly, regardless of the cause.

For small general service Customers whose load requirements are small, consistent, and can be accurately predicted, the billing demand may be determined, at the sole discretion of EDI, from the nameplate rating of the Customer's equipment rather than being metered.

The demand of certain equipment which is used for short periods of time, such as arc welders, does not fully register on the thermal demand meters. Points of Service which include this type of equipment may be billed on an estimated demand.

If requested by the Retailer, EDI will provide the Retailer with a description of the methodology used to estimate the use of energy by the Customers of the Retailer.

9.4 Other Metering Services

At the request by the Retailer, or with the Retailer's consent, EDI may provide other metering services, above standard metering service, in its discretion, acting reasonably, and may charge separate fees for such service.

9.5 Meter Testing

At the request of a Retailer, EDI shall arrange for on-site meter verification and if necessary, shall arrange for a meter to be tested by an official designated for that purpose by Measurement Canada or accredited agency as may, from time to time, be designated for this purpose. EDI charges a fee as set forth in the Fee Schedule. If the meter is inaccurate, EDI will refund the fee and make appropriate adjustments to the applicable Retailer's bills. If the meter is found to be accurate, EDI will keep the fee to cover the cost of testing the meter.

9.6 Adjustments for Faulty Metering

EDI may make consumption and demand adjustments for faulty metering:

(a) if the seal of a meter is broken or if the meter does not register correctly regardless of the cause;

(b) when a Point of Service has been unmetered or incorrectly metered, regardless of the cause, or when a meter is found to be inaccurate in accordance with the *Electricity and Gas Inspection Act*, R.S. 1985, c. E-4 as amended from time to time; in these cases EDI will make adjustments for a period not exceeding three (3) months, unless it can be shown that the error was due to some specific reported cause, the date of which can be fixed, in which case the actual date shall be used; or

(c) where a Point of Service is unmetered and any seal attached to motors or other equipment is broken or any unauthorized change in the Facilities has been made.

Notwithstanding the section "Adjustment of Bills in Event of Billing Error", in any of the above noted cases EDI may make adjustments for the lesser of the period of the error or one (1) year.

ARTICLE 10 – LOAD SETTLEMENT

10.1 Request for Information

A Retailer may request profiling and settlement information above the basic service provisions for Load Settlement specified in the Settlement System Code providing:

(a) the Retailer provides a written request to EDI outlining the purpose for the additional settlement information; and

(b) the additional settlement information applies only to the Customers of the Retailer.

Upon satisfaction of the above requirements, EDI will advise the Retailer in a written proposal of the type of work, time of delivery and charges necessary to provide the additional settlement information to the Retailer.

10.2 Liability

EDI shall not be liable to any person for any damages, cost, expense, injury, loss or other liability of any kind whatsoever, or however caused, resulting directly or indirectly from its good faith performance of its responsibilities under the Settlement System Code including its responsibilities as a load settlement agent, meter service provider or meter data manager. No express or implied warranties of any kind shall apply to information or services provided by EDI to any person as part of such good faith performance, including without limitation implied warranties of fitness for a particular purpose.

ARTICLE 11 – LIABILITY AND INDEMNITY

11.1 EDI Liability

Notwithstanding any other provision of these Terms and Conditions or any provision of any agreement between EDI and a Retailer relating to the provision of Distribution Tariff Services (an "EDI Agreement") EDI, its directors, officers, agents, employees and representatives ("EDI Parties") shall not be liable to the Customer, its directors, officers, agents, employees and representatives (collectively, the "Retailer Parties" and, individually, a "Retailer Party") for any loss, injury, damage, expense, charge, cost or liability of any kind suffered or incurred by the Retailer Parties, or any of them, whether of a direct, indirect, special or consequential nature, howsoever or whensoever caused, and whether in any way caused by or resulting from the acts or omissions of the EDI Parties, or any of them, except for direct property damages incurred by the Retailer as a direct result of a breach of these Terms and Conditions or applicable EDI Agreement or other act or omission by an EDI Party, which breach or other act or omission is caused by the negligence or willful act of harm of such EDI Party. Any liability under this Section will be limited to an amount in proportion to the degree to which the EDI Party acting negligently or willfully is determined to be at fault. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct property damage" shall not include loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of purchased or replacement capacity and energy, cost of capital, and loss of use of any facilities or property, or any other similar damage or loss whatsoever.

Any claim by a Retailer under this Section 11.1 must be filed with EDI within one hundred and eighty (180) days from the date of occurrence of the incident that is the subject of the claim, failing which the Retailer Parties will cease to have any claim against any EDI Party in respect of such incident.

11.2 Release

Subject to Section 11.1 above, none of the EDI Parties (as defined above) will be liable to any of the Retailer Parties (as defined above) for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by the Retailer Parties or any of them, howsoever and whensoever caused, and each Retailer Party hereby forever releases each of the EDI Parties from any liability or obligation in respect thereof.

11.3 Retailer Liability

11.3.1 General

In addition to any other liability provisions set out in these Terms and Conditions or any provision in an EDI Agreement (as defined above), a Retailer Party (as defined above) shall be liable for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by EDI Parties (as defined above), whether of a direct or indirect nature, caused by or arising from any acts or omissions of a Retailer Party that result in a breach ("Breach") of these Terms and Conditions or the applicable EDI Agreement, or any negligent or willful acts or omissions of harm of a Retailer Party outside of a Breach. Any liability under this section will be limited to an amount in proportion to the degree to which the Retailer Party is at fault.

11.3.2 Indemnification by Retailer of EDI for Third Party Claims

(a) A Retailer (the "Indemnitor") shall indemnify and hold harmless EDI Parties (as defined above) ("Indemnitee(s)") from and against any direct damages, injuries, losses and other liabilities claimed against the Indemnitee or any of them, and all related costs and expenses (including reasonable legal fees) suffered or incurred by any of them in relation to any claims, causes of action, actions, suits or proceedings by a third party ("Claim") which arise from damage to property or injury to or death of persons resulting from the Indemnitor's failure to perform its obligations under these Terms and Conditions or the applicable EDI Agreement (as defined above), which failure is caused by the negligence or willful act or omission of harm of the Indemnitor acting within the scope of its authority or employment. The indemnity under this section will be limited to an amount in proportion to the degree to which the Indemnitor is at fault.

(b) In the event that an Indemnitee is entitled to and desires to assert its right to indemnification from an Indemnitor under this Section, such Indemnitee will give the Indemnitor prompt notice of the Claim, which shall describe the Claim in reasonable detail and shall indicate the estimated amount, if practicable, of the indemnifiable loss that has been or may be sustained by the Indemnitee. The failure to promptly notify the Indemnitor hereunder shall not relieve the Indemnitor of its obligations hereunder, except to the extent that the Indemnitor is actually and materially prejudiced by the failure to so notify promptly.

(c) Subject to Section 11.3.2(b) hereof, if the Indemnitor delivers to the Indemnitee a written acknowledgement of its unconditional and irrevocable obligation to indemnify the Indemnitee under Section 11.3.2(a) in respect of:

(i) all of the damages, injuries, losses, liabilities, costs and expenses that may be claimed against, or suffered or incurred by, the Indemnitee in respect of the Claim within ten (10) days following the Indemnitor's receipt of the Indemnitee's notice of such Claim and if the existence of such obligation to indemnify is made known by the Indemnitor to the third-party claimant (and, if applicable, to the court or other tribunal determining the Claim), the Indemnitee shall make available to the Indemnitor all information in its possession or to which it has access, other than information that has been designated as confidential by the provider of such information, which is or may be relevant to the particular Claim and the Indemnitor shall be entitled, at its option, to take carriage of the defense of the Claim by its own counsel and, if it elects to do so, the Indemnitee shall cooperate with the Indemnitor to the fullest reasonable extent in the defense, settlement or compromise of the Claim; or

(ii) some, but less than all, of the damages, injuries, losses, liabilities, costs and expenses that may be claimed against, or suffered or incurred by, the Indemnitee in respect of the Claim within ten (10) days following the Indemnitor's receipt of the Indemnitee's notice of such Claim and if the Indemnitee is of the opinion that the Indemnitor's interests are not in conflict with its own, the Indemnitee shall make available to the Indemnitor all information in its possession or to which it has access, other than information that has been designated as confidential by the provider of such information, which is or may be relevant to that portion of the Claim in respect of which the Indemnitor has an obligation to indemnify the Indemnitee and consult with the Indemnitor in respect thereof.

The Indemnitee shall not make any admission of the liability regarding, or settle or compromise, that portion of the Claim in respect of which the Indemnitor has acknowledged its obligation to indemnify the Indemnitee without the written consent of the Indemnitor, which consent shall not be unreasonably withheld.

The provisions of this Section 11.3.2(c) shall not apply in respect of any Claim to which the Indemnitor is, or may reasonably be expected to be, a party and where the Indemnitee is asserting legal defenses in relation to the Claim that conflict with legal defenses being asserted by the Indemnitor.

ARTICLE 12 – FORCE MAJEURE

12.1 Force Majeure Relief

If an event or circumstance of Force Majeure occurs that affects EDI's ability to provide any Distribution Access Service, EDI's obligations and responsibilities hereunder and under any agreement relating to the provision of Distribution Access Service, so far as they are affected by the Force Majeure or the consequences thereof, shall be suspended until such Force Majeure or the consequences thereof are remedied and for such period thereafter as may reasonably be required to restore the Distribution Access Service. A Retailer will be required to continue to pay the Minimum Charge, if applicable, during the period in which EDI claims relief by reason of Force Majeure.

12.2 Notice

EDI shall promptly give the relevant party notice of the Force Majeure including full particulars hereof and shall promptly give the relevant party notice when the Force Majeure ceases to prevent performance of EDI's obligations.

12.3 Obligation to Remedy

EDI shall promptly remedy the cause and effect of the Force Majeure insofar as it is reasonably able to do so.

12.4 Strikes and Lockouts

Notwithstanding any other provision of these Terms and Conditions, the settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of EDI and EDI may settle such strike, lockout or industrial disturbance at such time and on such terms and conditions as it may deem appropriate. No failure or delay in settling such strike, lockout or industrial disturbance shall constitute a cause or event within the control of EDI or deprive EDI of the benefits of this Article 12.

ARTICLE 13 – DISPUTE RESOLUTION

13.1 Resolution by EDI and Retailer

If any dispute between EDI and a Retailer arises at any time in connection with these Terms and Conditions, EDI and the Retailer acting reasonably and in good faith, shall use all reasonable efforts to resolve the dispute as soon as possible in an amicable manner. If the dispute cannot be otherwise resolved pursuant to this Article 13, the chief executive officers of EDI and the Retailer shall meet to attempt to resolve the dispute.

13.2 Resolution by Arbitration

If any dispute has not been resolved pursuant to Section 13.1 hereof within thirty (30) days after notice from EDI or the Retailer to the other of its desire to have the dispute resolved, then the dispute shall be resolved pursuant to Sections 13.3 to 13.11 hereof. EDI and the Retailer shall abide by the terms of any award rendered by the arbitrator(s) appointed hereunder without delay.

13.3 Arbitrators

All disputes or differences between EDI and a Retailer in connection with these Terms and Conditions shall be referred (unless EDI and the Retailer concur in the appointment of a single arbitrator) to a board of arbitrators consisting of one (1) arbitrator to be appointed by each of EDI and the Retailer who shall, by instrument in writing, appoint a third arbitrator immediately after they are themselves appointed. Notwithstanding the foregoing, any disputed matters between EDI and a Retailer relating to an order or direction made or approved by the Board or falling within the exclusive jurisdiction of the Board, shall be referred to the Board for resolution.

13.4 Failure to Concur

EDI and a Retailer shall be deemed to have failed to concur in the appointment of a single arbitrator if such an arbitrator shall not have been appointed within fifteen (15) days after the serving by either EDI or the Retailer on the other of notice requesting it to concur in the appointment of such an arbitrator.

13.5 Refusal to Appoint an Arbitrator

If either EDI or the Retailer shall neglect or refuse to appoint an arbitrator within fifteen (15) days after the other party (provided such other party has appointed its arbitrator) has served EDI or the Retailer, as the case may be, with notice to make the appointment, the party who has appointed its arbitrator shall be entitled to apply, upon notice to the other party, to a Justice of the Court of Queen's Bench of Alberta to appoint an arbitrator for the party in default.

13.6 Failure to Appoint a Third Arbitrator

If the arbitrators appointed by EDI and the Retailer have not, within fifteen (15) days after their appointment or the appointment of the arbitrator last appointed, as the case may be, appointed a third arbitrator, either EDI or the Retailer shall be entitled to apply upon notice to the other party to a Justice of the Court of Queen's Bench of Alberta to appoint such an arbitrator.

13.7 Technical Competence

Any arbitrator appointed under the provisions of this clause whether by concurrence of EDI and the Retailer, by either party, by the arbitrators, or by a Justice of the Court of Queen's Bench of Alberta shall, in the opinion of the persons making such appointment, be possessed of such technical or other qualifications as may be reasonably necessary to enable him to properly adjudicate upon the dispute or difference.

13.8 Compensation of Arbitrators

Each party shall be responsible for the costs of the arbitrator appointed by it hereunder. The costs of the third arbitrator shall be divided evenly between the parties.

13.9 Application of the Arbitration Act (Alberta)

Except as herein modified, the provisions of the *Arbitration Act*, R.S.A., 2000, c. A-43, as amended from time to time, shall apply to any arbitration proceeding.

13.10 Decisions Binding

A decision of the single arbitrator or the majority of the three arbitrators named or appointed shall be final and binding upon each of the parties to the dispute or difference.

13.11 Continuity of Service

All performance required under these Terms and Conditions by EDI and the Retailer and payment therefore shall continue during the dispute resolution proceedings contemplated by this Article 13, provided that in the case of any such proceedings pertaining to amounts payable under these Terms and Conditions, any payments or reimbursements required as a result of the proceedings shall be effective as of a date to be determined in such proceedings and interest shall be paid thereon by the party required to make the payment or reimbursement on the amount thereof at the rate quoted by the Royal Bank of Canada as its "prime rate" from the date so determined until paid..

ARTICLE 14 – ADDITIONAL PROVISIONS RELATING TO SERVICES

14.1 Independent System Operation or Transmission Facility Owner Requirements

The Retailers acknowledge and agree that EDI is bound by all operating instructions, policies and procedures of the ISO and transmission facility owners which are needed to maintain the integrity of the Interconnected Electric System. The Retailers acknowledge and agree that they will cooperate with EDI so that EDI will be in compliance with all such operating instructions, policies and procedures which include, but are not limited to, those operating instructions, policies and procedures pertaining to minimum and maximum generation emergencies, and supply voltage reduction or full interruption of Customer load by either manual or automatic means.

14.2 Compliance with Applicable Legal Authorities

EDI and the Retailer are subject to, and shall comply with, all existing or future applicable federal, provincial and local laws, all existing or future orders or other actions of the ISO or of governmental authorities having applicable jurisdiction. EDI will not violate, directly or indirectly, or become a party to a violation of any applicable requirement of the ISO or any applicable federal, provincial or local statute, regulation, bylaw, rule or order in order to provide Distribution Tariff Services to the Retailer or a Customer of the Retailer. EDI's obligation to provide Distribution Tariff Services is subject to the condition that all requisite governmental and regulatory approvals for the provision of such Distribution Tariff Services will have been obtained and will be maintained in force during such period of Distribution Tariff Services.

14.3 Service Interruption

While EDI takes all reasonable efforts to guard against interruptions, it does not guarantee uninterrupted service. Without liability of any kind to EDI, EDI shall have the right to disconnect or otherwise curtail, interrupt or reduce Distribution Tariff Service to Customers whenever EDI reasonably determines, or when EDI is directed by the ISO, that such a disconnection, curtailment, interruption or reduction is:

(a) necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of EDI's Facilities;

(b) to maintain the safety and reliability of EDI's distribution system; or,

(c) due to any other reason including dangerous or hazardous circumstances including emergencies, forced outages, potential overloading of EDI's distribution system or Force Majeure.

14.4 No Assignment

A Retailer shall not assign any of its rights or obligations under these Terms and Conditions or any other agreement with EDI relating to Distribution Tariff Services without obtaining any necessary regulatory approvals and EDI's approval where required in such agreement. No assignment shall relieve the Retailer of any of its obligations under these Terms and Conditions until such obligations have been assumed by the assignee and EDI has agreed to the novation. Any assignment in violation of this section shall be void.

14.5 No Waiver

The failure of EDI or a Retailer to insist on any one or more instances upon strict performance of any provisions of these Terms and Conditions or any other agreement between EDI and a Retailer relating to Distribution Tariff Services, or to take advantage of any of its rights hereunder or thereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect. No term or condition of these Terms and Conditions or any other agreement between EDI and a Retailer relating to Distribution Tariff Services shall be deemed to have been waived and no breach excused unless such waiver or consent to excuse is in writing and signed by the party claimed to have waived or consented to excuse.

14.6 Law

These Terms and Conditions and any other agreement between EDI and a Retailer relating to Distribution Tariff Services shall be governed by the laws of the Province of Alberta and the federal laws of Canada applicable in the Province of Alberta, without regard to principles of conflicts of law. Any lawsuit arising in connection with these Terms and Conditions or any other agreement relating to Distribution Tariff Services shall be brought in the courts of the Province of Alberta.

SCHEDULE D-EDI DISTRIBUTION SERVICE CONNECTIONS TERMS AND CONDITIONS

EDI DAS Connections
T&Cs

(Consists of 44 pages)

TERMS AND CONDITIONS
FOR
DISTRIBUTION CONNECTION SERVICES

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ARTICLE 1 - INTRODUCTION TO TERMS AND CONDITIONS

These Terms and Conditions, as approved by the Alberta Energy and Utilities Board (the "Board"), form part of the Distribution Tariff of EPCOR Distribution Inc. ("EDI") and are established pursuant to section 102 of the *Electric Utilities Act 2003*, c. E-5.1. The Distribution Tariff is available for public inspection during normal business hours at the business offices of EDI and can be accessed on EDI's web site at:

www.epcor.ca/EPCOR+Companies/EPCOR+Distribution+and+Transmission/default.htm

These Terms and Conditions apply to EDI and its relationship with Customers including Load Customers and Distributed Generating Customers. All Customers by virtue of their relationship with EDI are deemed to have accepted these Terms and Conditions.

The service provided by EDI hereunder is regulated by the Board and parties having any inquiries or complaints regarding these Terms and Conditions may direct such inquiries or complaints directly to EDI or to the Board.

No agreement can provide for the waiver or alteration of any part of these Terms and Conditions unless such agreement is first filed with and approved by the Board. Whenever the Board approves an amendment to these Terms and Conditions, such amendment, including its effective date, will be posted on EDI's website at:

www.epcor.ca/EPCOR+Companies/EPCOR+Distribution+and+Transmission/default.htm

ARTICLE 2 - DEFINITIONS AND INTERPRETATION

2.1 Definitions

The following words and phrases, whenever used in these Terms and Conditions or in an application, contract or agreement for service under these Terms and Conditions, shall have the meanings set forth below:

"**Act**" means the *Electric Utilities Act*, S.A. 2003, c. E-5.1, as re-enacted, amended or replaced from time to time;

"**Available EDI Investment**" means the maximum investment that EDI will make to extend service to a Customer as set forth in Schedule A;

"**Board**" or "**EUB**" means the Alberta Energy and Utilities Board established under the *Alberta Energy and Utilities Board Act*, R.S.A., 2000, c. A-17, as re-enacted, amended or replaced from time to time;

"**Business Day**" means any day other than Saturday, Sunday or a holiday as defined in the *Interpretation Act*, R.S.A. 2000, c. I-8, as re-enacted, amended or replaced from time to time;

"**Commitment Agreement**" means the written agreement that may be required at EDI's sole discretion between a Customer and EDI whereby the Customer both authorizes the design and construction of new or expanded Facilities and agrees to pay all cancellation costs if the project is cancelled or if the Customer fails to sign an Electric Service Agreement prior to the energization of the new or expanded Facilities;

"**Connected Load**" means the sum of the capacities or ratings of the electric energy consuming apparatus connected or to be connected to EDI's electric distribution system;

"**Contract Term**" means the period of time during which the Customer continues to take service under these Terms and Conditions until service is no longer required;

"**Contracted Minimum Demand**" means the minimum Demand in kW or kVA specified in the Electric Service Agreement;

"**Customer**" includes a Load Customer and a Generating Customer;

"**Customer Contribution**" means the sum of the Distribution Contribution and the Transmission Contribution that the Customer shall pay to EDI to install the Facilities necessary to provide a Service Connection to the Customer.

"**Customer Usage Information**" means information regarding the historical electricity consumption of a Customer;

"**Default Supplier**" means a Retailer appointed by EDI pursuant to section 3 of the RRR Regulation;

"**Demand**" means the maximum rate at which Energy is delivered (expressed in kW, kVA or other suitable unit) at a given instant or averaged over any designated period of time;

"**Distributed Generation**" means a generating unit that is interconnected with EDI's electric distribution system.

"**Distributed Generation Customer**" means a person with on-site generating equipment that is interconnected with EDI's electric distribution system;

"**Distribution Access Service**" has the meaning given to it in the Act;

"**Distribution Extension Costs**" means the estimated costs of materials, labour, expenses, allocated overhead, and any other costs incurred by EDI in extending service to a particular Customer, related to distribution voltages of 25 kV and lower;

"**Distribution Contribution**" means the Distribution Capital Costs incurred in extending service to a Customer less the applicable level of any Available EDI Investment specified in Schedule A for the service;

"**Distribution Interconnection Agreement**" means an agreement entered into between EDI and a Distributed Generation Customer that sets out the provision and obligations of the parties with respect to the interconnection and is required when any Distributed Generation Customer interconnects to EDI's electric distribution system;

"**Distribution Tariff**" means a distribution tariff prepared by EDI and approved by the Board in accordance with section 102 of the Act;

"**Distribution Tariff Services**" means all services provided by EDI under the Distribution Tariff;

"**Dwelling**" means a private residence provided with sleeping and cooking facilities intended for domestic use and in which the occupants live as a single housekeeping unit that is not part of a Multiple Dwelling;

"**EDI**" means EPCOR Distribution Inc. or its successor;

"EDI Transmission Costs" has the meaning given to it in Section 7.3.1;

"**Electric Service Agreement**" means an agreement between EDI and a Customer for the provision of Distribution Access Service in relation to a Service Connection;

"**Electricity Services**" means the services associated with the provision of electricity to Customers, including the exchange of Energy, making financial arrangements to manage financial risk associated with the pool price, Distribution Access Service, system access service, ancillary services, billing, metering, performing load settlement and any other services specified in regulations made under the Act;

"**Energy**" means electric energy (expressed in kW);

"**Forecast Peak Demand**" means the expected maximum capacity requirement at a Point of Service which is used to determine the potential level of Available EDI Investment and the Contracted Minimum Demand;

"**Facilities**" means physical plant (including, without limitation, distribution lines, transformers, meters, equipment, machinery and other electrical apparatus) on EDI's side of the Point of Service interconnection excluding transmission facilities;

"**Fee Schedule**" means the fees and charges set forth in Table 2 of Schedule A - DAT Rate and Fee Schedule to EDI's Distribution Tariff;

"**Force Majeure**" means circumstances not reasonably within the control of EDI, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, mechanical breakdowns, the intervention of federal, provincial, state or local government or from any of their agencies or boards, the order or direction of any court, and any other cause, whether of the kind herein enumerated or otherwise;

"**Incremental Interconnection Costs**" means the costs of materials, labour, expenses and any other direct costs incurred by EDI to allow a Distributed Generation Customer to make use of EDI's electric distribution system.

"**Independent System Operator**" or "**ISO**" means the corporation established by section 7 of the Act;

"**In-service Date**" means the date on which the Customer specifies service is to be available or the date the service is actually available, whichever is later;

"**Interconnected Electric System**" means all transmission facilities and electric distribution systems in Alberta that are interconnected;

"**Interconnection Facilities**" for Distributed Generation Customers means all incremental distribution Facilities required to interconnect the circuits of the Distributed Generation Customer's generating facilities to EDI's Facilities and all modifications to EDI's distribution Facilities required for interconnection which may include, without limitation, poles, lines. substations, service leads and protective and metering equipment;

"**kVA**" means kilovolt-ampere or kilovolt-amperes;

"**kW**" means kilowatt or kilowatts;

"**kWh**" means kilowatt hour or kilowatt hours;

"**Load**" means the Demand and Energy delivered to or required at any Point of Service;

"**Load Customer**" means a person that is interconnected to EDI's electric distribution system for the purpose of purchasing electricity for the person's own use;

"**Load Settlement**" means "load settlement" as defined in the Act.

"**Minimum Charge**" means the higher of the rate minimum and the rate applied to the Contracted Minimum Demand;

"**Multiple Dwelling**" means a building containing more than one dwelling which share all or part of a Service Connection;

"**Point of Delivery**", or "**POD**" means the point at which electrical energy is transferred from a transmission facility owner's Transmission Facility to a distribution system and where the electric energy so transferred is measured;

"**Point of Service**" means the point at which EDI's service conductors are connected to the conductors or apparatus of a Customer;

"**Power Factor**" means the ratio of the highest metered Demand measured in KW in a fifteen (15) minute interval to the highest metered Demand measured in kVA in that same interval;

"**Power Pool**" means the scheme operated by the ISO under the Act for the exchange of Energy and financial settlement for the exchange of Energy;

"**Rate Schedules**" means the schedules of EDI's Distribution Tariff that set out charges;

"**RDS Regulation**" means the *Regulated Default Supply Regulation*, A.R. 168/2003, as amended from time to time;

"**RRR Regulation**" means the *Roles, Relationships and Responsibilities Regulation*, A.R. 169/2003, as amended from time to time;

"**Regulated Rate Tariff**' means a regulated rate tariff for the provision of Electricity Services to eligible customers prepared by EDI, or a person with whom EDI makes arrangements to do so, pursuant to section 102 of the Act;

"**Retail Electricity Services**" means Electricity Services provided directly to a Customer other than Electricity Services provided to eligible customers under a Regulated Rate Tariff;

"**Retailer**" means a person who sells or provides Retail Electricity Services directly to Customers and who is entitled to enroll Customers for Distribution Access Service under EDI's Terms and Conditions for Distribution Access Service, and includes a Default

Supplier, the person with whom EDI has made arrangements to provide the Regulated Rate Tariff to eligible Customers, and Self-Retailers;

"**Retailer of Record**" means the Retailer who is listed in EDI's records through the procedures outlined in its Terms and Conditions for Distribution Access Service, and thereby recognized by EDI and the Settlement System Code, as a particular Customer's Retailer for a Point of Service at a particular time;

"**Self-Retailer**" means a person carrying out Retailer functions to obtain Electricity Services solely for its own use;

"**Service Connection**" means the Facilities required to physically connect the Customer's facilities to EDI's electric distribution system to permit the Customer to obtain Distribution Access Service;

"**Settlement System Code**" means the rules respecting Load Settlement established by the Independent System Operator pursuant to the Act;

"**Site**" means a unique end-use Point of Service, being the finest level at which settlement recognizes retailer assignments, and receives consumption data;

"**System Access Service**" has the meaning given to it in the Act;

"**Transmission Contribution**" means the EDI Transmission Costs that are applicable to a particular Customer.

2.2 Conflicts

(a) If there is any conflict between a provision expressly set out in an order of the Board and these Terms and Conditions, the order of the Board shall govern.

(b) If there is any conflict between a provision in these Terms and Conditions, as may be amended from time to time, and a provision in an Electric Service Agreement or any other existing or future agreement between EDI and a Customer relating to a Service Connection or other interconnection to EDI's electric distribution system or Distribution Tariff Services, the provision in these Terms and Conditions shall govern.

2.3 Extended Meanings

In these Terms and Conditions, words importing the singular number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neutral genders and vice versa. Word importing a person shall include person, firm, partnership, corporation, organization or association (including, without limitation, individual members of any unincorporated entity).

2.4 Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

2.5 Schedules

The following schedules are attached to and form part of these Terms and Conditions:

Schedule A - Available EDI Investment

ARTICLE 3 - GENERAL PROVISIONS

3.1 Customer Guides

EDI has developed the Customer Connection Guide and Application Guide to Power Producers ("Guides") to help Customers understand the normal practices of EDI. EDI will amend the Guides, from time to time, to reflect changes to the electric utility industry, changes in EDI's requirements or the changing needs of EDI's Customers. While EDI will endeavour to follow practices in the Guides, these practices will not appropriately cover every situation that may arise and it may be necessary to deviate from the Guides. A copy of the Guides can be accessed on EDI's website at www.epcor.ca.

3.2 Fees and Other Charges

EDI will provide all standard services hereunder pursuant to the Distribution Tariff. All additional, supplementary or extra non-discretionary services provided by EDI to a Customer will be charged a separate rate or fee such as those included, without limitation, in the Fee Schedule.

3.3 Billing Customers

EDI may bill the Customers directly for Customer Contributions, meter tests and other services covered in these Terms and Conditions. A late payment charge of 2.0% per month (26.82% per annum) is applied if the Customer's payment has not been received by EDI before one month from the date the bill was issued. The Customer is charged a dishonoured cheque charge for each cheque returned for insufficient funds as set forth in the Fee Schedule.

ARTICLE 4 - APPLICATION FOR SERVICE CONNECTION

4.1 Information Requirements

To enable EDI to provide the requested service, applicants for service shall supply information regarding the location of the premises to be served, the Customer's Connected Load and preferred supply conditions and the manner in which the Service Connection will be utilized, credit information or reference and any other information that may be required by EDI. The Customer shall refer to EDI's Customer Connection Guide for customary information requirements.

Upon receipt of the required information, EDI will advise the applicant of the type and character of the Service Connection it will furnish to the Load Customer, and any special conditions that must be satisfied.

4.2 Application

All Customers must be of legal age to contract for service with EDI. EDI reserves the right to verify the identity of the Customer and the accuracy of the information provided and to require the Customer to sign an application in writing on forms provided by EDI.

For commercial and industrial Customers, written acceptance specifying the Customer has agreed to these Terms and Conditions must be received by EDI before construction of the service will proceed.

A Customer may be required to sign a Commitment Agreement before construction of the Service Connection will proceed.

A Retailer or any other person acting as an agent of a Customer may apply for a Service Connection on behalf of the Customer. The Retailer or agent must provide EDI, in a form acceptable to EDI, verifiable authorization from the Customer to make the application.

4.3 Rejection of Application

EDI may, without limitation, reject any applicant's request for a Service Connection when:

(a) the Customer does not have currently in force all authorizations that may be required for the installation of the Service Connection in accordance with Section 4.5; or

(b) EDI determines that the form of the Electric Service Agreement is not appropriate for the Service Connection due to its unique nature and the Customer refuses to enter into an alternate form of agreement acceptable to EDI; or

(c) any representation made by the applicant or the Customer to EDI for the purpose of obtaining a Service Connection is, in EDI's opinion, fraudulent, untruthful or misleading; or

(d) the Customer has not, when requested by EDI to do so, provided a signed written application for a Service Connection, Electric Service Agreement or Commitment Agreement; or

(e) the type of Service Connection applied for is not available or not normally provided by EDI in the locality where the Service Connection is requested; or

(f) the requirements of the Customer Connection Guide have not been met; or

(g) the proposed Connected Load, in EDI's opinion, have unusual characteristics that might adversely affect the quality of service supplied to other Customers, the public safety, or the safety of EDI's personnel or EDI's Facilities.

4.4 Customer Contracts

4.4.1 Electric Service Agreement

Customers connected or connecting to EDI's electric distribution system may be required by EDI to sign an Electric Service Agreement in respect of a Service Connection. Customers with an Forecast Peak Demand of less than 150 kVA generally are not required to sign an Electric Service Agreement. The Electric Service Agreement shall be signed by the Customer and not by a Retailer or any other person acting as an agent of the Customer.

The initial term of the Customer's Electric Service Agreement shall be effective on the date service is first made available to the Point of Service.

If the Customer continues to take service beyond the initial term, the Electric Service Agreement remains in effect until terminated by either party in accordance with Article 13.

4.4.2 Commitment Agreement

EDI, in its sole discretion, may require a Customer to sign a Commitment Agreement, to be in effect until an Electric Service Agreement is executed or the request for a Service Connection has been cancelled.

4.4.3 Transfer of Contractual Obligations

All services, whether or not they require EDI assignment consent, that are properly transferred to an affiliate or successor taking over the operation of an existing facility shall be subject to the terms of the previous Customer's Electric Service Agreements and billing and Demand history. Any change in service requirements as a result of such transfer shall be made in accordance with these Terms and Conditions. The existing contractual arrangements will remain in place until any new agreements have been approved and accepted by both parties.

4.5 Authorizations

The Customer for a Service Connection shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations necessary for the installation and operation of the Service Connection. EDI shall not be required to commence or continue installation or operation of a Service Connection unless and until the Customer has complied with the requirements of all governmental authorities, permits, certificates, licenses, inspections, reports and other authorizations, all right-of-way agreements, and all of EDI's requirements applicable to the installation and operation of the Service Connection. EDI reserves the right, but is not obligated, to verify that all necessary authorizations have been obtained by applicants and Customers.

4.6 Temporary Service

Where EDI reasonably believes that a requested service will be temporary, it may require the Customer requesting the service to pay EDI in advance of a Service Connection, the estimated cost of Facilities plus the estimated cost of installation and removal of Facilities necessary for the desired service, less the value of the salvaged material.

4.7 Information and Requirements for Service

4.7.1 Service Connection Information

Upon request, EDI shall provide to the Customer information on the method and manner of making Service Connections. Such information may include a copy of EDI's Customer Connection Guide, a description of the Service Connection available, location of entrance Facilities and metering equipment, and Customer and EDI responsibilities for installation of facilities.

4.7.2 Customer Usage Information

EDI shall provide standard Customer Usage Information to an agent or consultant, acting on behalf of a Customer, upon request and only after receiving written consent to such disclosure from the Customer, for the 12-month period preceding the date of the request or for such shorter period for which EDI has collected that information.

Prior to requesting EDI to release Customer Usage Information, the agent or consultant shall be responsible for obtaining and providing to EDI the written authorization from the Customer referred to above in a form satisfactory to EDI

Customer Usage Information, with the exception of interval data, will be provided by EDI at no additional cost.

4.8 Connection Fee

The actual costs including, without limitation, the meter connection costs, account setup costs, and the initial meter read costs will be charged to the Customer at the time of construction.

ARTICLE 5 - SERVICE REQUIREMENTS AND FACILITIES

5.1 Scheduling for Service Connection

After the Customer has complied with EDI's application requirements and has been accepted for service by EDI and complied with the requirements of Section 4.5 and all other local construction, safety standards or regulations, EDI shall schedule that Customer for Service Connection.

5.2 Protection of EDI's Equipment

5.2.1 Interference with EDI Facilities

The Customer shall not install or allow to be installed on property owned or controlled by the Customer any temporary or permanent structures that could interfere with the proper and safe operation of EDI's Facilities or result in non-compliance with applicable statutes, regulations, standards or codes.

5.2.2 Protection of Installed Facilities

The Customer shall furnish and maintain, at no cost to EDI, the necessary space, housing, fencing, barriers, and foundations for the protection of the Facilities to be installed upon the Customer's premises. If the Customer refuses, EDI may, at its option, furnish and maintain, and charge the Customer for furnishing and maintaining, the necessary protection. Such space, housing, fencing, barriers and foundations shall be in conformity with applicable laws and regulations and subject to EDI's specifications and approval.

5.2.3 Power Factor

A Customer shall design, install and operate its facilities in such a manner as to maintain a Power Factor of not less than 90%. EDI may require any Customer not satisfying this Power Factor requirement to furnish, install, and maintain, or EDI may install at the Customer's cost, such remedial or corrective equipment as EDI may deem necessary under the circumstances.

5.2.4 Compliance with Requirements and Use of Service Connection

The Customer shall ensure that its facilities comply with the applicable requirements of the *Canadian Electrical Code* and with any other technical guidelines that may be issued from time to time by EDI. The Customer shall not use its Service Connection or Distribution Tariff Services in a manner so as to cause interference with any other Customer's use of a Service Connection or Distribution Tariff Services such as abnormal voltage levels, frequency levels and harmonic levels. At EDI's request, the Customer shall take whatever action is required to correct the interference or disturbance at the Customer's expense.

5.2.5 Operation of Generator Facilities

Notwithstanding the provisions in Article 9, the Customer shall not, without the written consent of EDI, use its own generator facilities in parallel operation with EDI's electric distribution system.

5.3 Relocation of Facilities

The Customer shall pay all costs of relocating EDI's Facilities at the Customer's request, for the Customer's convenience, or if necessary to remedy any violation of law or regulation caused by the Customer. If requested by EDI, the Customer shall pay the estimated cost of the relocation in advance.

5.4 Extensions

A Customer shall not extend or permit the extension of facilities connected to EDI's distribution system beyond property owned or occupied by that Customer for any Point of Service.

ARTICLE 6 - RIGHTS OF WAY AND ACCESS TO FACILITIES

6.1 Easements

At the request of EDI, the Customer shall grant, or cause to be granted, to EDI, without cost to EDI, such easements or rights-of-way over, upon or under the property owned or controlled by the Customer as EDI reasonably requires for the construction, installation, maintenance, repair, and operation of the Facilities required for a Service Connection to the Customer and the performance of all other obligations required to be performed by EDI hereunder.

6.2 Right of Entry

EDI's employees, agents and other representatives shall have the right to enter a Customer's property at all reasonable times for the purpose of installing, maintaining, replacing, testing, monitoring, reading or removing EDI's Facilities and for any other purpose incidental to the provision of a Service Connection and the Customer shall not prevent or hinder EDI's entry. EDI will endeavour to provide reasonable notice to the Customer when it requires entry to the Customer's property.

6.3 Vegetation Management

The Customer shall permit EDI to manage vegetation on the property owned or controlled by the Customer to maintain proper clearances and reduce the risk of contact with EDI's Facilities. EDI shall make reasonable efforts to notify the Customer before such work is performed.

ARTICLE 7 - DISTRIBUTION AND TRANSMISSION EXTENSION

7.1 General Requirements

7.1.1 EDI Investment

The investment available from EDI in relation to the extension of service to a Customer is set out in Schedule A and will apply to the types of services specified in Schedule A. The Forecast Peak Demand will be used for establishing the investment available and the Contracted Minimum Demand.

7.1.2 Estimated Cost

Upon an applicant's request for a Service Connection, EDI shall prepare a proposal outlining the estimated cost of the Service Connection and Customer Contribution to be paid by the applicant.

7.1.3 Agreement in Writing

All agreements requiring payment by the Customer or investment by EDI shall be in writing and signed by each party.

7.1.4 Application

The provisions of this Article 7 apply to those Customers who, in EDI's judgement, will have a permanent Service Connection with EDI. Customers for temporary service shall be governed by Section 4.6 concerning temporary service applications.

7.1.5 Changes

The payment, if any, required by Section 7.1.2 is based on EDI's assumptions respecting the method of construction and the routing of the Facilities required to serve the Customer in accordance with the Customer's request for a Service Connection. If the assumed method of construction or routing of Facilities is changed for reasons beyond EDI's reasonable control as a result of which EDI would incur costs in excess of those estimated on the basis of such assumptions, then the Customer shall pay to EDI the amount by which the cost of such changed method of construction and/or routing of Facilities is estimated by EDI to exceed such costs as originally estimated. EDI will outline the estimated costs and the Customer shall make payment to EDI as set out in the Customer's proposal as so revised, provided that in such case the Customer shall have the right to cancel its Electric Service Agreement by paying to EDI all costs then incurred by EDI in respect of the Service Connection requested.

7.2 Determination of Distribution Extension Costs and Distribution Contributions

7.2.1 Distribution Extension Costs

The Distribution Extension Costs incurred by EDI in extending service to a Customer may consist of the following:

(a) the local Facilities required to extend service for the sole purpose of an individual Customer;

(b) where a new extension will serve a number of new Customers, an amount that represents a share of the total capital cost of the shared extension as follows:

$$\frac{\text{(Customer's Forecast Peak Demand) X (Distribution Extension Costs)}}{\text{(Total expected demand served by extension)}}$$

(c) if the Customer extension requires an upgrade to EDI's Facilities, the upgrade costs incurred by EDI may form part of the Customer's extension cost; and

(d) if a Customer or a well defined group of Customers request EDI to advance the upgrade of existing Facilities, the costs of the upgrade including but not limited to, incremental higher costs associated with construction in a season other than what would be normally be done, carrying costs, and higher construction costs associated with additional mobilization and demobilization from advancing the construction of Facilities, may be classified as customer-related.

7.2.2 Customer Distribution Contribution

If the total Distribution Extension Costs are less than the investment available from EDI as specified in the Fee Schedule for the service, the Customer will not be required to make any contribution. In all other cases, the Customer will be required to pay a Distribution Contribution and an agreement for payment of the Distribution Contribution must be made between the Customer and EDI before any work on the extension is commenced.

Under no circumstances will the level of Available EDI Investment exceed the Distribution Extension Costs.

7.3 Determination of EDI Transmission Costs and Transmission Contributions

7.3.1 EDI Transmission Costs

EDI may incur transmission costs ("EDI Transmission Costs") as a result of entering into contracts for provision of System Access Service in support of Customers' electricity supply requirements. EDI Transmission Costs include but are not limited to contributions and application fees made by EDI in respect of a Point of Delivery providing System Access Service to a Customer. The EDI Transmission Costs incurred by EDI in extending service to a Customer are allocated in accordance with the following:

(a) Where a single Customer is served from one Point of Delivery, the Customer's Transmission Contribution will be equal to the total EDI Transmission Costs incurred by EDI.

(b) Where a number of new Customers are served from a new Point of Delivery, each Customer may be allocated a portion of the EDI Transmission Costs as follows:

$$\frac{\text{(Customer's Forecast Peak Demand) X (EDI Transmission Costs)}}{\text{(Total expected demand at the Point of Delivery)}}$$

This allocated cost becomes the Customer's Transmission Contribution.

(c) Where EDI Transmission Costs are incurred by EDI for an expansion or extension to an existing Point of Delivery which is required to provide System Access Service to an identifiable Customer(s) with increased Energy requirements, the EDI Transmission Costs may be allocated to each such Customer based on the proportion of their increase in Forecast Peak Demand relative to the total increased in expected demand as the Point of Delivery. This allocated amount becomes the Customer's Transmission Contribution.

7.3.2 Customer Transmission Contribution

If a Transmission Contribution is applicable to a Customer, then an agreement for payment of the Transmission Contribution must be made between the Customer and EDI before any work on the extension is commenced.

7.4 Changes in Point of Delivery Demand

EDI reserves the right to pass through to the Customer any costs from the ISO incurred by it as a direct result of:

(a) EDI being required to establish a new POD contract, or increase to the contract demand in an existing POD contract, or

(b) a change in the Customer's service requirements resulting in costs that EDI would not otherwise recover, or

(c) the Customer terminating service as provided Section 13.2.

7.5 Refunds of Contributions

When a Customer provides a Distribution Contribution under section 7.2 to obtain service at Point of Service, EDI may refund a portion of the contribution if the events referred to in this Section occur during the initial term of the Customer's Electric Service Agreement.

7.5.1 Change in Contracted Minimum Demand

A Customer at an existing Point of Service may receive a refund where an Electric Service Agreement with an increased Contracted Minimum Demand is executed as described in the section "Changes to Service Requirements".

7.5.2 Cost Sharing

If a new Customer shares the costs of an existing extension, a Customer may receive a refund based on the proportion of the costs of the shared extension that are used by the new loads relative to the total load supplied by the shared extension. Refunds, in whole or in part, are made without interest to the current Customer at the Point of Service.

No refund in relation to a Distribution Contribution shall be payable unless an event referred to in this Section occur during the initial term of the Electric Service Agreement.

Customer Transmission Contributions may be refunded to a Customer in whole or in part, if EDI receives a refund of EDI Transmission Costs which can be attributed to the Customer.

7.6 Delay in Taking Service

In circumstances where EDI will install Facilities to serve a subdivision or a multiple dwelling residence, and it is determined that service will not be taken within twelve (12) months of the In-service Date, the Customer shall pay for the entire cost of the new extension. For each Point of Service in the subdivision or multiple dwelling residence that is energized within five (5) years of the In-service Date, EDI will refund the payment for each Point of Service based on any applicable Available EDI Investment level specified in Schedule A. Otherwise, EDI shall be entitled to retain such payment as compensation for its costs incurred.

7.7 Conversion from Overhead to Underground Service

A Customer may request that existing EDI Facilities be converted from overhead to underground service. The Customer, or any other person who is acting on behalf of a Customer and who provides EDI with verifiable authorization from the Customer, will be charged for all costs incurred by EDI in connection with the conversion, including, without limitation, the following:

(a) the present value of future revenue streams associated with the existing Facilities which are being removed, plus

(b) the estimated cost of removing the existing Facilities, less the estimated salvage value, plus

(c) the estimated cost for the installation of the new underground Facilities, less any investment that may be available from EDI as specified in Schedule A.

ARTICLE 8 - SERVICE CONNECTION

8.1 Customer Responsibility

8.1.1 Facilities and Service Connection

The Customer shall be responsible for the installation and condition of all facilities on the Customer's side of the Point of Service. The Customer shall be responsible for any destruction of or damage to EDI's Facilities where the destruction or damage is caused by a negligent act or omission or wilful misconduct of the Customer, its directors, officers, agents, employees and representatives or anyone permitted by the Customer to be on the premises.

The Customer assumes full responsibility for the proper use of the Service Connection or the service provided by EDI and for the condition, suitability and safety of any and all wires, cables, devices or equipment energized on the Customer's premises or on premises owned or controlled by the Customer that are not the Customer's property.

8.1.2 Protective Devices

The Customer shall be responsible for determining whether the Customer needs any devices to protect the Customer's facilities from damage that may result from the use of a Service Connection or Distribution Tariff Services. The Customer shall provide and install any such devices.

8.1.3 Service Calls

EDI may require a Customer to pay the actual costs of a requested service call if the source of the problem is the Customer's facilities.

8.1.4 Standards for Connection

The Customer's installation shall conform to the requirements of EDI's Customer Connection Guide and/or such further requirements as EDI may establish from time to time. Copies of such guidelines are available on request and from EDI's website.

8.1.5 Interference with EDI's Property

No one other than an employee or authorized agent of EDI shall be permitted to remove, operate, or maintain meters, electric equipment and other EDI Facilities. The Customer shall not interfere with or alter the meter, seals or other Facilities or permit the same to be done by any person other than the authorized agents or employees of EDI. The Customer shall be responsible for all damage to or loss of such property unless occasioned by circumstances as determined in EDI's sole discretion to have been beyond the Customer's control, such as "Acts of God" and other similar circumstances. Such Facilities shall be installed at points most convenient for EDI's access and service and in conformance with applicable laws and regulations in force from time to time.

8.2 Unauthorized Use

Where EDI determines that there has been unauthorized use of the Service Connection or Distribution Tariff Services including, but not limited to, meter tampering, unauthorized connection or reconnection, theft, fraud, intentional or unintentional use of energy whereby EDI is denied full compensation for services provided, EDI will bill the Customer or its Retailer for EDI's estimate of such unauthorized use. Nothing in this section shall limit any other rights or remedies that EDI may have in connection with such unauthorized use.

8.3 Multiple Dwellings

Each individual unit within a multiple dwelling will be served as a separate Point of Service, unless EDI agrees otherwise.

Where EDI and a Customer have agreed that service to a multiple dwelling shall be delivered through a single Point of Service, the applicable general service (non-residential) price schedule will apply to the service.

8.4 Mobile Homes

Service shall normally be provided to mobile homes through separate Points of Service, based on the applicable residential price schedule.

Service provided to common use areas (e.g. laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service price schedule.

In mobile home parks or trailer courts where EDI reasonably believes homes are temporary, EDI may elect to provide service only through the Point of Service billed to the mobile home park or trailer court.

8.5 Frequency and Voltage Levels

EDI will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and as specified in the Customer Connection Guide. Some voltage levels set out in the Customer Connection Guide may not be available at all locations served by EDI.

8.6 Minimum Charges

The Minimum Charge calculated in accordance with the Rate Schedules will be applicable

ARTICLE 9 - DISTRIBUTED GENERATION CUSTOMERS

9.1 General

This Article sets out specific terms and conditions related to Distributed Generation Customers that are in addition to any applicable terms and conditions set out in other Articles of these Terms and Conditions.

Distributed Generation Customers have generating facilities that are interconnected to EDI's electric distribution system and may or may not be exporting Energy to the Interconnected Electric System. Distributed Generation Customers may also have on site load requirements or generator stand-by/supplemental load requirements to which the applicable terms and conditions of these Terms and Conditions will apply.

All Distributed Generation Customers are required to enter into a Distribution Interconnection Agreement with EDI to establish detailed terms, conditions and provisions with respect to safe and effective operation of the specific interconnection.

9.2 Interconnection

A Distributed Generation Customer or other person acting on behalf of the Distributed Generation Customer must apply in writing for interconnection to EDI's electric distribution system. The application must include all relevant information concerning site location, facility requirements and requested export levels. Any requested changes to these requirements must be provided in writing to EDI.

The interconnection of a generator to EDI's electric distribution system must not create a safety hazard to Customers, the public or operating personnel, nor compromise the reliability, power quality or effective operation of the Interconnected Electric System or any part thereof and shall comply with all applicable legislation, policies, standards, rules or codes of federal, provincial or local regulatory entities, the Power Pool, the ISO or electric distribution or transmission facility owners, as they may change from time to time.

Prior to interconnecting generating facilities to EDI's electric distribution system, the Distributed Generation Customer shall:

(a) satisfy all participant and application requirements of the Power Pool (if the generator is producing electricity beyond on-site requirements thereby exporting into the Interconnected Electric System and exchanging Energy through the Power Pool);

(b) comply with all applicable requirements of EDI including its Technical Guideline for Interconnection of Generators to the Distribution System, as amended from time to time;

(c) obtain and provide copies of required permits, licences and authorization to EDI including the Board's approval and order to connect and acceptance from the local inspection and code enforcement authorities;

(d) satisfy all requirements of EDI in relation to the generating facility metering set out in Section 9.3.5 below;

(e) execute a Distribution Interconnection Agreement with EDI; and

(f) execute an agreement with EDI which will specify technical and operating requirements if it wishes to operate in parallel operation with or as supplementary, auxiliary or stand-by-service to any other source of Energy.

9.3 Distributed Generation Customer Responsibilities

9.3.1 Responsibility for Facilities and use of Service

The Distributed Generation Customer will be responsible for the design, installation, maintenance and condition of all facilities on the Distributed Generation Customer's side of the Point of Service, except metering or other equipment owned by EDI.

The Distributed Generation Customer shall comply with all applicable requirements of EDI including its Technical Guideline for Interconnection of Generators to the Distribution System, as amended from time to time

The Distributed Generation Customer shall be responsible for any destruction of or damage to EDI's Facilities where the destruction or damage is caused by a negligent act or omission or wilful misconduct of the Distributed Generation Customer, its directors, officers, agents, employees and representatives or anyone permitted by the Customer to be on the premises.

The Distributed Generation Customer assumes full responsibility for the proper use of the service provided by EDI and for the condition, suitability and safety of any and all wires, cables, devices or equipment energized on the Distributed

Generation Customer's premises or on premised owned or controlled by the Distributed Generation Customer that are not the Distributed Generation Customer's property.

9.3.2 Protective Devices

The Distributed Generation Customer shall be responsible for determining whether it needs any devices to protect its equipment from damage that may result from the interconnection to EDI Facilities. The Distributed Generation Customer shall provide and install any such devices. The Distributed Generation Customer will provide EDI with the required documentation and settings for such devices. Where EDI has determined that there are adverse impacts on other Customers or operating processes, EDI can order modifications to such devices. The Distributed Generation Customer must obtain written approval from EDI for any modifications to such devices.

The Distributed Generation Customer must use tele-protection signals or other such reliable means to separate the generator from the Interconnected Electric System during islanding conditions. The Distributed Generation Customer shall be responsible for any damages that are caused as a result of failure to safely separate during an islanding situation.

9.3.3 Disconnection for Safety Reasons

In addition to the provisions of Section 15.7, the Interconnection Facilities will include an acceptable visible disconnect switch as a means of isolating the Distributed Generation Customer's generating facilities from EDI's electric distribution system. EDI may disconnect a DG Customer's generating facilities from EDI's electric distribution system without prior notice where in EDI's opinion::

(a) the Distributed Generation Customer has violated the terms of the Distribution Interconnection Agreement with EDI; or

(b) the Distributed Generation Customer has permitted its facilities to deteriorate and become hazardous; or

(c) the Distributed Generation Customer facilities fails to comply with applicable standards and requirements of EDI including those as set out in EDI's Application Guide to Power Producers or its Technical Guideline for Interconnection of Generators to the Distribution System, as amended from time to time; or

(d) the use of the service may cause damage to EDI's Facilities or interfere with or disturb service to any other Customer.

EDI will reconnect the service when the safety problem is resolved and when the Distributed Generation Customer has provided, or paid EDI's costs of providing, such devices or equipment as may be necessary to resolve such safety problems and to prevent damage, interference or disturbance.

9.3.4 Service Calls

EDI may require a Distributed Generation Customer to pay the actual costs of a requested service call if the source of the problem is the Distributed Generation Customer's facilities.

9.3.5 Metering and Settlement

(a) The Distributed Generation Customer will be responsible for installing bi-directional, four-quadrant metering facilities to measure active energy and reactive energy produced by the generator, and consumption of power, active energy and reactive energy, flowing from the electric distribution system to the Distributed Generation Customer's facilities. The metering facilities shall be in compliance with the standards set by EDI.

(b) Where export of power to the Interconnected Electric System is not required, the Distributed Generation Customer will be responsible for installing uni-directional, two quadrant metering to separately record active and reactive power.

(c) At the request of EDI, the Distributed Generation Customer shall install additional metering facilities if EDI determines that the existing metering facilities are inadequate or not properly configured to measure the full consumption flowing from EDI's distribution system to the Distributed Generation Customer's facilities. EDI reserves the right to install additional metering, at the Distributed Generation Customer's cost, as it deems necessary to ensure accurate measurement of consumption from EDI's distribution system.

(d) The power production information must be provided to EDI, the ISO and the Power Pool at and frequency which is acceptable to these entities. EDI may use the power production information for internal use.

(e) The Distributed Generation Customer must provide EDI with consumption information in a form acceptable to EDI whether or not the Distributed Generation Customer consumes power from EDI's distribution system.

(f) Upon receipt of a request by the Distributed Generation Customer, EDI will install bi-directional, four quadrant metering facilities to measure active and reactive energy as identified in Section 9.3.5(a). EDI will be responsible to interrogate the meter and perform all settlement transactions with the ISO and the Power Pool. The Distributed Generation Customer will be provided with consumption and power production information for its internal use. The Distributed Generation Customer will be responsible for the costs of providing and installing the metering equipment and ongoing operating costs

(g) Telemetry is required for all generating units in excess of 5MW in capacity, or where EDI has determined that telemetry is required in order to maintain reliable operation of the distribution system.

9.3.6 Meter Test

EDI reserves the right to request meter test information from the Distributed Generation Customer.

If metering facilities have been removed for reasons such as, but not limited to, testing or inspection, EDI may estimate the demand and amount of energy supplied, but not registered, at the Point of Service.

EDI may, at any reasonable time, read, inspect, remove and test a meter owned or controlled by the Distributed Generation Customer. EDI shall have the right to enter a Distributed Generation Customer's property for the purpose of reading, inspecting, testing or removing the meter, and the Distributed Generation Customer shall not prevent or hinder EDI's entry.

9.3.7 Energy or Demand Diversion

If under any circumstance a Distributed Generation Customer prevents a meter from accurately recording the total Demand or Energy supplied from EDI's distribution system, or the consumption information has been found corrupted, EDI may disconnect the service, or take other appropriate actions to ensure access to accurate meter data.

EDI may then estimate the Demand and amount of Energy supplied but not registered at the Point of Service. The Distributed Generation Customer shall pay the cost of the estimated Demand and Energy consumption, plus all costs related to the investigation and resolution of the diversion.

9.3.8 Permits, Licences and Authorizations

The Distributed Generation Customer shall obtain and provide to EDI copies of all required permits, licenses and other authorizations prior to any change in service requirements at any point of interconnection, which include:

(a) any required approval of the Board; and

(b) acceptance from the local inspection and code enforcement authorities.

9.3.9 Approvals

The Distributed Generation Customer must obtain written approval from EDI before any modification is made to the Distributed Generation Customer's system.

The Distributed Generation Customer will be responsible for becoming and maintaining its status as a Power Pool participant and complying with any Power Pool requirements for any Energy delivered to the Power Pool (if the generator is producing electricity beyond on-site requirements thereby exporting into the Interconnected Electric System and exchanging Energy through the Power Pool).

The Distributed Generation Customer will be responsible for securing all required technical, commercial, or operational arrangements with ISO and the Power Pool.

The Distributed Generation Customer will be responsible for providing technical information to EDI as required. EDI will treat this information as confidential and will not release such information to any other parties without the express and written consent of the Distributed Generation Customer.

The Distributed Generation Customer will be responsible for operating in compliance with accepted industry operating and maintenance standards as established, from time to time, by the ISO and EDI, and as specified in the Interconnection Agreement between the Distributed Generation Customer and EDI. EDI shall have the right to inspect the Distributed Generation Customer's facilities for compliance.

EDI will be responsible for providing technical information to the Distributed Generation Customer as required. The Distributed Generation Customer will treat this information as confidential and will not release such information to any other parties without the express and written consent of EDI.

9.4 Incremental Interconnection Costs

The Distributed Generation Customer will be required to pay all incremental interconnection costs as determined by EDI, to allow the Distributed Generation Customer to make use of EDI's electric distribution system, including:

(a) any costs of connection to EDI's electric distribution system, including any cost sharing to Load Customers;

(b) any costs to upgrade existing distribution facilities;

(c) an application fee associated with performing engineering estimates, planning, operating or protection studies or any additional or routine modelling and testing required by the ISO;

(d) any costs of protection, anti-islanding circuitry, communication facilities, telemetry or modification to distribution or transmission facilities required to reliably separate the generator from the electric system.

An agreement for payment of the incremental costs must be made between the Distributed Generation Customer and EDI before any work on the interconnection is commenced;

The Distributed Generation Customer shall be required to pay all replacement costs for all incremental interconnection facilities including the replacement of assets at the end of useful life or replacement due to failure, including but not limited to, elements such as transformers, poles, regulators, capacitors, line conductor, and teleprotection systems. EDI may provide the Distributed Generation Customer with an option to pay for the replacement costs over time as provided in section 9.5.

If a new Customer or Distributed Generation Customer shares a portion or all of an existing extension, to which the interconnection costs relates, EDI will refund a portion of the Distributed Generation Customer's contribution based on the amount of extension shared and the ratio of the Distributed Generation Customer's operating Load to the total operating Load.

9.5 Payment Options and Credit Requirements

9.5.1 Payment Option

EDI may provide the Distributed Generation Customer with an option to pay for the incremental interconnection costs determined under section 9.4 over time, providing the Distributed Generation Customer satisfies the credit requirements listed herein. The payment period will not exceed five years.

9.5.2 Minimum Financial Criteria

Subject to review and reassessment of the creditworthiness of a Distributed Generation Customer by EDI from time to time, EDI has established the following minimum financial criteria for Distributed Generation Customers requesting to pay for the incremental costs over time. The Distributed Generation Customer will be deemed to have met the credit requirements if:

(a) the Distributed Generation Customer or an affiliate or person which guarantees the financial obligation of the Distributed Generation Customer in a manner acceptable to EDI has at least an "A" rating for its senior, unsecured, non-credit enhanced, long term from Standard and Poor's bond rating service or an equivalent rating from a major reputable bond rating service satisfactory to EDI; or

(b) the Distributed Generation Customer provides, in a manner acceptable to EDI, a bank guarantee, irrevocable letter of credit, or cash deposits drawn on a Canadian Chartered Bank, a trust company, credit union or other lending institution that is acceptable to EDI.

9.5.3 Required Credit Information

EDI will require the following minimum information and supporting documentation to conduct a credit risk assessment of the Distributed Generation Customer.

(a) most recent credit rating report from a recognized rating agency and a list of bank credit and trade references, including address, phone numbers and bank officer;

(b) audited financial statements for the latest two years (two most recent annual report to shareholders, if applicable);

(c) description of the corporate structure, including the name of the chief executive officer and chief financial officer;

(d) legal name, address, phone, and fax numbers of the Distributed Generation Customer; and

(e) certificate specifying the names, titles, and specimen signatures of the persons authorized to approve and confirm contracts.

9.5.4 Costs

All costs associated with obtaining financial security and meeting prudential requirements are the responsibility of the Distributed Generation Customer.

ARTICLE 10 - METERS

10.1 Installation of Meters

10.1.1 Provision and Ownership

EDI shall provide, install, and seal one or more meters for the purpose of measuring the Energy delivered to a Customer by way of a Service Connection. Time of use or interval meters and associated communication equipment shall be installed for a Customer who has a connected load exceeding 150 kW. Each meter shall remain the sole property of EDI.

10.1.2 Responsibility of Customer

Each Customer shall provide and install a Canadian Standards Association approved meter receptacle or other Canadian Standards Association approved facilities suitable for the installation of EDI's meter or metering equipment.

10.2 Location

Meter locations shall be approved by EDI based on type of service and convenience of access to the meter. Where a meter is installed on a Customer-owned pole, the pole shall be provided and maintained by the Customer as required by the *Canadian Electrical Code* and any applicable legislation.

10.3 Access to Meters

EDI may, at any reasonable time, read, inspect, remove and test a meter installed on property owned or controlled by the Customer.

Upon written request to EDI, the Customer may access pulse data directly from its interval meter. The Customer Connection Guide sets out the method in which costs are to be recovered.

10.4 Meter Testing

At the request of a Customer, EDI shall arrange for on-site meter verification and if necessary, shall arrange for a meter to be tested by an official designated for that purpose by Measurement Canada or accredited agency as may, from time to time, be designated for this purpose. EDI charges a fee as set forth in the Fee Schedule. If the meter is inaccurate, EDI will refund the fee and make appropriate adjustments to the applicable bills. If the meter is found to be accurate, EDI will keep the fee to cover the cost of testing the meter.

10.5 Energy or Demand Diversion

If under any circumstances, a person other than an EDI employee, agent or contractor, prevents a meter from accurately recording the total demand or energy supplied, EDI may disconnect the service, or take other appropriate actions to ensure access to accurate meter data.

EDI may then estimate the demand and amount of energy supplied but not registered at the Point of Service. The Customer shall pay the cost of the estimated demand and energy consumption plus all costs related to the investigation and resolution of the diversion.

10.6 Changes to Metering Equipment

Should a Customer request new metering equipment beyond the basic service, EDI shall provide, install, test and maintain the required metering equipment. The metering equipment must be requested in writing by the Customer and meet EDI's requirements. The Customer shall bear the cost of providing and installing the metering equipment, and ongoing operating costs. The costs for upgrading to an interval meter is as set forth in the Fee Schedule. For changes to metering equipment on primary distribution voltage levels, the cost of providing and installing such metering equipment and the ongoing operating costs, will be determined on a case be case basis.

The metering equipment shall become the property of EDI and will be maintained by EDI. EDI shall complete installation of the metering equipment within thirty (30) days of delivery from the supplier. EDI shall bill the Customer prior to installation and the Customer shall prepay the cost of installation. at least fifteen (15) Business Days prior to proposed installation date. If payment is not received by fifteen (15) Business Days prior to the proposed installation date, EDI shall have no obligation to proceed with the installation.

Should a Customer request to return the metering equipment to its previous basic form, the Customer shall bear the cost of removal and installation of the metering equipment.

Upon request by the Customer, EDI may provide other metering services, above standard metering service, in its discretion, acting reasonably, and may charge separate fees for such service.

ARTICLE 11 - CHANGE IN SERVICE

11.1 Changes to Service Requirements

A Customer shall give to EDI reasonable prior written notice of any change in requirements at a Point of Service, including any change in Load to enable EDI to determine whether or not it can accommodate such revised service without changes to its Facilities. Regardless of whether alterations are required to existing Facilities, if the Customer's Forecast Peak Demand increases, a new Electric Service Agreement must be executed based on the new Forecast Peak Demand. A Retailer, or any other person acting on behalf of a Customer, who provides EDI with verifiable authorization from the Customer may give such notice to EDI on the Customer's behalf. If EDI receives such notice from a Retailer or other person, EDI may at its option require such notice directly from the Customer.

The Customer shall not change its requirement for at a Point of Service without EDI's written permission. The Customer shall be responsible for all damage caused to EDI's electric distribution system as the result of the Customer changing its requirements for a Service Connection without EDI's permission.

11.2 Changes to EDI Facilities

If EDI determines it must modify its Facilities to accommodate a change in a Customer's requirements for a Service Connection, a Customer Distribution Contribution may apply and such contribution will be determined as provided in Section 7.2. A new Electric Service Agreement must be executed to reflect the additional investment made by EDI.

11.3 Impact of Changes on Customer's Electric Service Agreement

11.3.1 Increases

Notwithstanding any other provisions in the Terms and Conditions, a new Electric Service Agreement with a revised Contracted Minimum Demand value is required before the Customer may increase its service requirements for a Service Connection.

For a Customer which has provided a Distribution Contribution under section 7.2, EDI will calculate a contribution refund based on the increase in the Contracted Minimum Demand. The refund will not exceed the amount of the prior Customer Distribution Contribution.

A Customer will only be entitled to a refund if the Customer's Contracted Minimum Demand is increased within the initial term of the Electric Service Agreement

11.3.2 Decreases

If a Customer's Forecast Peak Demand decreases, the Customer's Contracted Minimum Demand shall not be reduced.

11.4 Changes to System Access Costs

If EDI must modify its arrangements with the ISO to accommodate a change in Customer's service requirements, the Customer pays for all costs attributable to such modification, including, but not limited to, additional contributions required from EDI by the ISO. The attributable costs are determined as described in the section "Determination of EDI Transmission Costs and Transmission Contributions".

ARTICLE 12 - SERVICE DISCONNECTION AND RECONNECTION

12.1 Disconnection by Customer

12.1.1 Temporary Disconnection

Upon the request of the Customer, EDI shall temporarily disconnect any Service Connection provided:

(a) the Customer agrees to pay any charges made to EDI by the ISO that will not be recovered as a direct result of the Customer's idle service;

(b) upon the request to restore service the Customer will be responsible for and pay any applicable charges outlined under section 12.3; and

(c) if the Service Connection remains disconnected for more than twelve (12) months, it will be considered permanently disconnected and Section 12.1.2 will apply.

12.1.2 Discontinuance of Distribution Access Service and Permanent Disconnection

Customers arrange for termination of Distribution Access Service through their Retailer of Record.

If the Customer requests that the Service Connection be permanently disconnected, the Customer billing for that service will be finalized. At the discretion of EDI, the Facilities provided by EDI will be removed.

If within three (3) years of permanent disconnection the Customer requests the Service Connection be restored, the Customer must pay all the costs associated with the original disconnection, removal of the Facilities and restoration of service.

12.2 Disconnection by EDI

12.2.1 Disconnection without Notice

If EDI believes there is any actual or threatened danger to life or property, or in any other circumstances, the nature of which, in EDI's sole judgment requires such action, EDI has the right to withhold connection or to disconnect a Customer's Service Connection without prior notice to the Customer. More specifically, and without limitation of the foregoing, EDI may exercise this right in the event that::

(a) in the opinion of EDI, the Customer has permitted the Customer's facilities to become hazardous, the Customer's facilities fail to comply with applicable statutes, standards and codes and/or EDI requirements, or if the use of the Service Connection may cause damage to any other Service Connection or facilities;

(b) to the knowledge of EDI, or in its sole judgement, the Customer's facilities are unsafe or defective or will become unsafe or defective imminently. In this event, the Service Connection may not be restored until the Customer facilities are approved by the appropriate authority. EDI shall provide written notice to the Customer within a reasonable time of the reason for the disconnection under this subsection and the actions required for reconnection;

(c) on account of theft by the Customer of any EDI Facilities;

(d) if any tampering with any service conductors, seals or any other Facilities of EDI or any meters, whether or not provided by EDI is discovered; or

(e) if the Customer changes its requirements for a Service Connection or Distribution Tariff Services without the permission of EDI.

(b) If the disconnection is a result of a safety violation, EDI will reconnect the service when the safety problem is resolved and when the Customer has provided, or paid EDI's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

12.2.1 Disconnection with Notice

EDI may withhold connection or may disconnect a Customer's Service Connection (without prejudice to any of EDI's other remedies) after providing forty-eight (48) hours advance notice to the Customer, as applicable, in the following circumstances:

(a) if the Customer neglects or refuses to pay when due any amounts required to be paid under these Terms and Conditions (which amount is not the subject of a good faith dispute);

(b) as required by law;

(c) if the Customer is in violation of any of these Terms and Conditions or any of the terms of an Electric Services Agreement with EDI;

(d) any other similar circumstances to those described above that EDI determines, in its sole discretion, acting reasonably, require the withholding or disconnecting of service upon forty-eight (48) hours notice.

EDI also reserves the right to install a current-limiting device to restrict the capability of the Distribution Tariff Services.

12.3 Reconnect Service

This Section applies to reconnection or restoration of service to a Customer whose service was previously restricted by a current-limiting device or discontinued (whether at the request of the Customer or not).

Before reconnecting or restoring service, the Customer shall pay:

(a) any amount owing to EDI including written off accounts; and

(b) a reconnection charge that will billed to the Customer's Retailer.

12.4 Removal of Facilities

Upon termination of service, EDI shall be entitled to remove any of its Facilities located upon the property of the Customer and to enter upon the Customer's property for that purpose.

ARTICLE 13 - CONTRACT EXIT PROVISIONS

A Customer's Electric Service Agreement remains in effect, subject to the right of either EDI or the Customer to terminate such agreement upon thirty (30) days written prior notice being given to the other party.

Upon receipt of such notice, EDI shall read the Customer's meter within a reasonable time, and, shall use all reasonable efforts to read the Customer's meter at the time requested by the Customer. A Customer shall pay for all service provided up to the time of such reading.

13.1 Distribution Related Exit Charge

When a Customer with an Electric Service Agreement no longer requires service from EDI, and it is within the initial term of the Electric Service Agreement, in addition to any other applicable requirements under these Terms and Conditions, the Customer may be required to pay a "Distribution Related Exit Charge".

The Distribution Related Exit Charge is:

(a) the present value of future revenue streams associated with the existing Facilities being removed; less

(b) the estimated salvage value; plus

(c) the estimated salvage costs; plus

(d) plus any outstanding amounts attributable to the Customer with respect to, but not limited to, any deferral accounts and Board approved riders and charges arising from services supplied by EDI prior to the termination of service.

Distribution Customer Exit Charge provisions apply for the service life of EDI's investment, as established at the time of investment.

13.2 Transmission Related Exit Charge

When a Customer no longer requires service from EDI, in addition to any other applicable requirements under these Terms and Conditions, the Customer may be required to pay a "Transmission Related Exit Charge".

The Transmission Related Exit Charge is:

(a) any costs charged to EDI by the ISO that are attributable to the Customer's termination of service; and

(b) any ongoing costs that EDI will be required to pay the ISO, that will not be recovered as a result of the Customer's termination of service.

ARTICLE 14 - LIABILITY AND INDEMNITY

14.1 EDI Liability

Notwithstanding any other provision of these Terms and Conditions or any provision of any agreement between EDI and a Customer relating to the provision of Distribution Tariff Services (an "EDI Agreement") EDI, its directors, officers, agents, employees and representatives ("EDI Parties") shall not be liable to the Customer, its directors, officers, agents, employees and representatives ("Customer Parties") for any loss, injury, damage, expense, charge, cost or liability of any kind suffered or incurred by the Customer Parties, or any of them, whether of a direct, indirect, special or consequential nature, howsoever or whensoever caused, and whether in any way caused by or resulting from the acts or omissions of the EDI Parties, or any of them, except for direct property damages incurred by the Customer as a direct result of a breach of these Terms and Conditions or applicable EDI Agreement or other act or omission by an EDI Party, which breach or other act or omission is caused by the negligence or wilful act of harm of such EDI Party. Any liability under this Section will be limited to an amount in proportion to the degree to which the EDI Party acting negligently or wilfully is determined to be at fault. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct property damage" shall not include loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of purchased or replacement capacity and energy, cost of capital, and loss of use of any facilities or property, or any other similar damage or loss whatsoever.

Any claim by a Customer Party under this Section 14.1 must be filed with EDI within one hundred and eighty (180) days from the date of occurrence of the incident that is the subject of the claim, failing which the Customer Party will cease to have any claim against any EDI Party in respect of such incident.

14.2 Release

Subject to Section 14.1 above, none of the EDI Parties (as defined above) will be liable to any of the Customer Parties (as defined above) for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by the Customer Parties or any of them, howsoever and whensoever caused, and each Applicable Party hereby forever releases each of the EDI Parties from any liability or obligation in respect thereof.

14.3 EDI Not Liable to Customer

For greater certainty and without limitation to the foregoing in Sections 14.1 and 14.2, EDI Parties (as defined above) shall not be liable to a Customer for any damages of any kind (except to the extent EDI is liable for such damages in accordance with Section 14.1):

(a) caused by or arising from any EDI Party's conduct in compliance with, or as permitted by, these Terms and Conditions, the Terms and Conditions for Distribution Access Service, a Distribution Services Agreement between EDI and a Retailer or any legal or regulatory requirements related to service provided to Retailers;

(b) caused to the Customer and arising from any failure of a Retailer to comply with the Terms and Conditions for Distribution Access Service, any agreement with EDI relating to Distribution Tariff Services or for any damages caused by or arising from equipment installed or actions taken by a Retailer;

(c) caused by or arising from a Retailer's failure to perform any commitment to the Customer, including but not limited to the Retailer's obligation, including its obligation under Part 8 of the Act, to provide Retail Electricity Services including Distribution Tariff Services to the Customer; or

(d) caused by or resulting from any acts, omissions or representations made by a Retailer in connection with soliciting Customers for Distribution Access Service or performing any of the Retailer's functions in providing Retail Electricity Services including Distribution Tariff Services to Customers.

14.4 Customer Liability

In addition to any other liability provisions set out in the Terms and Conditions or any provision in an EDI Agreement, a Customer Party (as defined above) shall be liable for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by EDI Parties (as defined above), whether of a direct or indirect nature, caused by or arising from any acts or omissions of an Customer Party that result in a breach ("Breach") of these Terms and Conditions or the applicable EDI Agreement, or any negligent or wilful acts or omissions of harm of a Customer Party outside of a Breach. Any liability under this section will be limited to an amount in proportion to the degree to which the Customer Party is at fault.

14.5 Force Majeure

14.5.1 Force Majeure Relief

If an event or circumstance of Force Majeure occurs that affects EDI's ability to provide a Service Connection or other interconnection to its electric distribution system or Distribution Tariff Services, EDI's obligations and responsibilities hereunder and under any agreement relating to Service Connections or other interconnections to its electric distribution system or the provision of Distribution Tariff Services, so far as they are affected by the Force Majeure or the consequences thereof, shall be suspended until such Force Majeure or the consequences thereof are remedied and for such period thereafter as may reasonably be required to restore the Distribution Tariff Services. The Minimum Charge, if applicable, will continue to be payable during the period in which EDI claims relief by reason of Force Majeure.

14.5.2 Notice

EDI shall promptly give the relevant party notice of the Force Majeure including full particulars hereof and shall promptly give the relevant party notice when the Force Majeure ceases to prevent performance of EDI's obligations.

14.5.3 Obligation to Remedy

EDI shall promptly remedy the cause and effect of the Force Majeure insofar as it is reasonably able to do so.

14.5.4 Strikes and Lockouts

Notwithstanding any other provision of these Terms and Conditions, the settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of EDI and EDI may settle such strike, lockout or industrial disturbance at such time and on such terms and conditions as it may deem appropriate. No failure or delay in settling such strike, lockout or industrial disturbance shall constitute a cause or event within the control of EDI or deprive EDI of the benefits of this Section 14.5.

ARTICLE 15 - ADDITIONAL PROVISIONS RELATING TO SERVICES

15.1 Ownership of Facilities

(a) EDI remains the owner of all Facilities necessary to provide Distribution Access Service to the Customers, unless an agreement between EDI and a Customer specifically provides otherwise.

(b) Payment made by Customers for costs incurred by EDI in installing Facilities does not entitle Customers to ownership of any such Facilities, unless an agreement between EDI and a Customer specifically provides otherwise.

15.2 Distribution Access Service Obtained from Retailer

EDI will not initiate or continue Distribution Access Service at a Point of Service unless the Customer is enrolled to obtain Distribution Access Service. It is the Customer's responsibility to make arrangements with a Retailer to obtain Retail Electricity Services, including enrolment for Distribution Access Service.

15.3 Proper Use of Services

The Customers assume full responsibility for the proper use of the Service Connection and Distribution Tariff Services provided by EDI and for the condition, suitability and safety of any and all wires, cables, devices or appurtenances energized by energy on the Customer's premises or on premises owned or controlled by the Customer that are not the Customer's property. The Customer shall be liable for any loss, damage, expense, charge, cost or other liability of any kind, whether to EDI, its agents or employees, EDI property or otherwise, arising directly or indirectly by reason of: (i) the routine presence in or use of energy over the wires, cables, devices or other Facilities owned or controlled by the Customer; (ii) the Customer's improper or negligent use of energy or electric wires, cables, devices or other facilities; or (iii) the negligent acts or omissions or wilful acts or omissions of the Customer or any person permitted on the Customer's property.

15.4 Independent System Operation or Transmission Facility Owner Requirements

The Customers acknowledge and agree that EDI is bound by all operating instructions, policies and procedures of the ISO and transmission facility owners which are needed to maintain the integrity of the Interconnected Electric System. The Customers acknowledge and agree that they will cooperate with EDI so that EDI will be in compliance with all such operating instructions, policies and procedures which include, but are not limited to, those operating instructions, policies and procedures pertaining to minimum and maximum generation emergencies, and supply voltage reduction or full interruption of Customer load by either manual or automatic means.

15.5 Compliance with Applicable Legal Authorities

EDI and the Customers are subject to, and shall comply with, all existing or future applicable federal, provincial and local laws, all applicable existing or future orders or other actions of the ISO or of governmental authorities having applicable jurisdiction. EDI will not violate, directly or indirectly, or become a party to a violation of any applicable requirement of the ISO or any applicable federal, provincial or local statute, regulation, bylaw, rule or order in order to provide a Service Connection or Distribution Tariff Services to the Customers. EDI's obligation to provide a Service Connection or Distribution Tariff Services is subject to the condition that all requisite governmental and regulatory approvals for the provision of the Service Connection or Distribution Tariff Services will have been obtained and will be maintained in force during such period of service.

15.6 Interference with EDI's Property

No one other than an employee or authorized agent of EDI shall be permitted to remove, operate, or maintain meters, electric equipment and other Facilities owned by EDI. The Customers shall not interfere with or alter the meter, seals, or other Facilities or permit the same to be done by any person other than the authorized agents or employees of EDI.

15.7 Service Interruption

While EDI takes all reasonable efforts to guard against interruptions, it does not guarantee uninterrupted service. Without liability of any kind to EDI, EDI shall have the right to disconnect or otherwise curtail, interrupt or reduce Distribution Access Service to Customers whenever EDI reasonably determines, or when EDI is directed by the ISO, that such a disconnection, curtailment, interruption or reduction is:

(a) necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of EDI's Facilities;

(b) to maintain the safety and reliability of EDI's electric distribution system; or,

(c) due to any other reason including dangerous or hazardous circumstances including emergencies, forced outages, potential overloading of EDI's electric distribution system or Force Majeure.

15.8 No Assignment

A Customer shall not assign any of its rights or obligations under these Terms and Conditions or any other agreement with EDI relating to a Service Connection or Distribution Tariff Services without obtaining any necessary regulatory approvals and EDI's approval where required in such agreement. No assignment shall relieve the Customer of any of its obligations under these Terms and Conditions until such obligations have been assumed by the assignee and EDI has agreed to the novation. Any assignment in violation of this section shall be void.

15.9 No Waiver

The failure of EDI or a Customer to insist on any one or more instances upon strict performance of any provisions of these Terms and Conditions or any other agreement between EDI and the Customer relating to a Service Connection or Distribution Tariff Services, or to take advantage of any of its rights hereunder or thereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect. No term or condition of these Terms and Conditions or any other agreement between EDI and a Customer relating to a Service Connections or Distribution Tariff Services shall be deemed to have been waived and no breach excused unless such waiver or consent to excuse is in writing and signed by the party claimed to have waived or consented to excuse.

15.10 Law

These Terms and Conditions and any other agreement between EDI and a Customer relating to a Service Connection or Distribution Tariff Services shall be governed by the laws of the Province of Alberta and the federal laws of Canada applicable in the Province of Alberta, without regard to principles of conflicts of law. Any lawsuit arising in connection with these Terms and Conditions or any other agreement relating to a Service Connection or Distribution Tariff Services shall be brought in the courts of the Province of Alberta.

SCHEDULE A — AVAILABLE EDI INVESTMENT

1. Maximum Investment

The maximum investment that EDI will make in new services or expansions for General Service and Industrial Customer classes is $225 per kVA of Minimum Contacted Demand for the first 2,500 kVA and $100 per kVA thereafter.

2. Eligibility for Investment

(a) The following Facilities are eligible for investment:

- distribution 3 phase and single phase extensions
- transformers
- standby feeder where required by EDI
- cable and lines on private property up to the meter

(b) The following Facilities are not eligible for investment:

- transformer pad and civil works on private property
- standby feeders not required by EDI
- underground services in aerial areas
- other facilities which are not reasonably required to provide electric service

(c) Raw land Underground Industrial Distribution ("UID") servicing costs are not eligible for investment. However, the Service Connections to specific Customers locating in UID areas are eligible for investment.

(d) Overtime premiums, where requested by the customer, are excluded from the maximum investment allowance and shall be paid by the Customer.